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.

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 the 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.

PJM does not provide a market for black start services, which are procured and paid zonally, but does ensure that there are adequate black start resources.

1 75 FERC ¶ 61,080 (1996).
2 Regulation is used to help control the area control error (ACE). See *2008 State of the Market Report,* Volume II, Appendix F, “Ancillary Service Markets,” for a full definition and discussion of ACE. Regulation resources were almost exclusively generating units in 2008.
3 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).

The MMU analyzed measures of market structure, conduct and performance of the PJM Regulation Market and of its two Synchronized Reserve Markets for 2008, comparing market results to 2007. The Market Monitoring Unit (MMU) also analyzed measures of market structure, conduct and performance of the PJM DASR Market from June 1 through December 31, 2008.

Overview

Regulation Market

There were no major structural changes to the PJM Regulation Market in 2008 which continues to be operated as a single market. On December 1, 2008, PJM implemented several changes to the Regulation Market including the introduction of the three pivotal supplier test for market power, a change to the calculation of lost opportunity cost and a change to the treatment of regulation revenues with respect to operating reserve credits.

Market Structure

- **Supply.** During 2008, the supply of offered and eligible regulation in PJM was generally both stable and adequate. Although PJM rules allow up to 25 percent of the regulation requirement to be satisfied by demand resources, none qualified to make regulation offers in 2008. The ratio of eligible regulation offered to regulation required averaged 2.39 throughout 2008.

- **Demand.** From January 1 through August 7, 2008, PJM calculated the regulation requirement for all hours of the day as 1.0 percent of the peak load forecast for the operating day. This requirement was established in August 2006. Beginning August 7, PJM began to calculate on-peak and off-peak regulation requirement. The on-peak requirement is equal to 1.0 percent of the forecast peak load for the PJM RTO for the day. The PJM RTO off-peak Regulation Requirement is equal to 1.0 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand in 2008 was 922 MW. For the winter the demand was 960 MW; for the spring it was 834 MW; for the summer it was 1,064 MW; and for the fall it was 815 MW. For the months of August through December, average off-peak regulation demand was 665 MW while average on-peak demand was 881 MW.

- **Market Concentration.** During 2008, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1283 which is classified as "moderately concentrated."[4] The load weighted average HHI before August 1 (when the requirement was fixed for all hours of the day) was 1226. The load weighted average HHI after August 1 when the requirement was lower for off-peak hours, was 1397. The minimum hourly HHI was 707 and the maximum hourly HHI was 2767. The largest hourly market share in any single hour was 58 percent, and 63 percent of all hours had a maximum market share greater than 20 percent. In 2008, 82 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these results that the PJM Regulation Market in 2008 was characterized by structural market power in 82 percent of the hours.

4 See the *2008 State of the Market Report*, 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).

Market Conduct

- **Offers.** From January through November 2008 regulation offer prices were provided by the unit owner, applicable for the entire operating day and, with lost opportunity cost (LOC), comprised the total offer to the Regulation Market. The regulation offer price was subject to a $100 per MWh offer cap, with the exception of the two dominant suppliers, whose offers were capped at marginal cost plus $7.50 per MWh plus LOC. All suppliers are paid the market-clearing price. Beginning December 1, 2008 PJM implemented a three pivotal supplier test in the regulation market. As part of the implementation, owners are required to submit unit specific cost based offers which may include up to a $12/MWh margin adder and owners have the option to submit price based offers. All offers remain subject to the $100 per MWh cap. All units owned by owners who fail the three pivotal supplier test for an hour are dispatched at the lesser of their cost based or price based offer. As part of the changes to the regulation market implemented on December 1, 2008, PJM no longer nets regulation revenue above offer price against operating reserve revenue and PJM now calculates lost opportunity costs using the lower of cost based or price based offers as the reference rather than the cost based offer.

Market Performance

- **Price.** For the PJM Regulation Market during 2008 the load weighted, average price per MWh (i.e., the regulation market clearing price, including LOC) associated with meeting PJM's demand for regulation was $42.09. This represents an increase of $5.37 from the average price for regulation during 2007. From January through November 2008, based on MMU estimates of the marginal cost of regulation, offers at levels greater than competitive levels set the clearing price for regulation in about 18 percent of all hours. On December 1, 2008, PJM implemented new Regulation Market rules that cost cap units offered by suppliers which are pivotal and allow price based offers for units whose suppliers are not.

Synchronized Reserve Market

There were no major structural changes to the PJM Synchronized Reserve Market in 2008.[5] Throughout 2008 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).

In September 2008, PJM made a change to the market clearing software, Synchronized Reserve and Regulation Optimizer (SPREGO), designed to improve the accuracy of Tier 1 estimates and reduce the amount of Tier 2 synchronized reserve called by PJM dispatchers after the market cleared. These additional assignments made by the dispatchers are to meet increases in required synchronized reserves that occur after needed synchronized reserve is first forecast 90 minutes before the operating hour. The changes were made to address a problem in the Synchronized Reserve Market that has been persistent since late 2007.

5 In PJM, the term, Synchronized Reserve Market, refers to Tier 2 synchronized reserve. Synchronized Reserve as it is used here is 10-minute operating reserve.

In mid-January 2009, PJM Market Operations took the unusual step of recalculating, revising, and reposting synchronized reserve market clearing prices for November and early December 2008. Some hours had been erroneously calculated because validation data required by a software change had not been entered. In all, nine hours were reposted. The price changes ranged from a reduction of $30.38 to a reduction of $429.83 and included one hour where there was a price increase of $11.23.

Market Structure

- **Supply.** During 2008, the offered and eligible excess supply ratio was 1.41 for the PJM Mid-Atlantic Synchronized Reserve Region.[6] The excess supply ratio is determined using the administratively required synchronized reserve. The actual requirement for Tier 2 synchronized reserve is lower because there is usually a significant amount of Tier 1 synchronized reserve available. Throughout 2008, the MW contribution of DSR resources to the Synchronized Reserve Market remained significant and resulted in lower overall Synchronized Reserve prices.

- **Demand.** The average synchronized reserve requirements were 1,310 MW for the RFC Synchronized Reserve Zone and 1,160 MW for the Mid-Atlantic Subzone. These requirements are a function of administratively determined, regional requirements established by each market zone's reliability council. Since there was usually enough Tier 1 in the RFC Synchronized Reserve Zone to cover the requirement, only 5 percent of hours cleared a Tier 2 Synchronized Reserve market in the RFC. For the Southern Synchronized Reserve Zone only 1.5 percent of the hours had a non-zero Tier 2 requirement in 2008. Market demand is less than the requirement by the amount of forecast Tier 1 synchronized reserve available at the time a Synchronized Reserve Market is cleared. The average demand for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone was 153 MW. Demand for Tier 2 Synchronized Reserve fell sharply in December as a result of a large increase in the forecast Tier 1 available. The average demand for Tier 2 synchronized reserve in the Southern Synchronized Reserve Zone was 1.5 MW. All demand for Tier 2 in the Southern Synchronized Reserve Zone was satisfied by 15-minute quick start units. A Southern Synchronized Reserve Zone market did not clear in any hours in 2008.

  The purchase of additional Tier 2 synchronized reserves by dispatchers after synchronized reserve market settlement continued to be an issue in 2008. In 2008, 44 percent of all Tier 2 synchronized reserves were added after the market cleared. It is clear that, in actual operations, PJM dispatch identifies a need for more Tier 2 synchronized reserve, or differently located synchronized reserve, than is being forecast and scheduled through the Tier 2 Synchronized Reserve Market. It is clear that there is a difference in the calculation of the need for Tier 2 synchronized reserves between the market solution and the operators. The reason remains under investigation.

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

- **Market Concentration.** Although lower than in 2007, market concentration in the Tier 2 Synchronized Reserve Markets remained high in 2008. The average load weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone throughout 2008 was 2844. Slightly less than one percent of all hours had a market share of 100 percent. In 56 percent of hours the maximum market share was greater than 40 percent (compared to 76 percent of hours in 2007). In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, in 2008, 96 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these results that the PJM Synchronized Reserve Markets in 2008 were characterized by structural market power.

Market Conduct

- **Offers.** The offer price is provided by the unit owner, is applicable for the entire operating day and, with lost opportunity cost calculated by PJM, comprises the merit order price to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost.

Market Performance

- **Price.** The load weighted, average PJM price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market was $10.65 per MW in 2008, a $5.63 per MW decrease from 2007.

- **Demand.** There was a significant change in the operation of the Synchronized Reserve Market in the last quarter of 2007 as PJM relied less on the market and more on out of market purchases of spinning reserve for local needs. This continued throughout 2008. The increase in out of market purchases indicates that the Synchronized Reserve Market is not functioning to adequately coordinate supply and demand. It is not clear why the demand identified in the market solution is consistently less than the demand identified by the system operators.

- **DSR.** Demand side resources began participating in the Synchronized Reserve Markets in August 2006. Participation of demand response grew significantly in late 2007, leveled off through August of 2008 and rose significantly in September through December of 2008. In 32 percent of hours during 2008 in which a Tier 2 Synchronized Reserve Market was cleared for the Mid-Atlantic Subzone, all synchronized reserve was provided by DSR.

- **Availability.** A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced deficits during 2008.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[7] 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 by the reliability region.[8] 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

The DASR Market in 2008 had three pivotal suppliers in a monthly average of 45 percent of all hours. The number of hours in which the DASR Market had three pivotal suppliers declined in November and December. The MMU concludes from these results that the PJM DASR Market in 2008 was characterized by structural market power.

Market Conduct

In December, about 6 percent of all units engaged in economic withholding from the DASR Market by providing high offer prices. Conversely, about 48 percent of units had offers of $0.00, either by choice or by default.

Market Performance

For June 2008 through December 2008, the load weighted price of DASR was $0.26. DASR prices declined in the last three months of 2008. Demand side resources began to offer and clear in the DASR Market in November and became significant in December.

Black Start

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 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.[9]

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.

7 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).
8 PJM Manual 13, Emergency Requirements, Rev 35, 11/07/2008; pp 11-12.
9 PJM Tariff, Second Revised Sheet No. 33.01, March 1, 2007.

PJM does not have a market to provide black start reserve, but compensates black start resource owners for all costs associated with providing this service, as defined in the tariff. For 2008, charges to PJM members for providing black start services were just over $13 million.

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

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

Conclusion

PJM consolidated its Regulation Markets into a single Combined Regulation Market, on a trial basis, effective August 1, 2005. The MMU has consistently found since that time that the PJM Regulation Market is characterized by structural market power. This conclusion is based on the results of the three pivotal supplier test. In 2008, the MMU cannot conclude that the Regulation Market produced competitive results or noncompetitive results, based on the MMU analysis of the relationship between the offer prices and marginal costs of units that set the price in the Regulation Market, the marginal units, where the MMU finds that prices were set by offers above the competitive level in 18 percent of the hours. The absence of a definitive conclusion is a result of the fact that the cost data are based on MMU estimates rather than data submitted by market participants. It is expected that the application of the three pivotal supplier test will mean that the results of the Regulation Market will be competitive in 2009.

In 2008, PJM and its stakeholders addressed the issue of market power mitigation for the Regulation Market in the Three Pivotal Supplier Task Force (TPSTF), which was convened pursuant to PJM's 2007 Strategic Report to review market power mitigation issues.[10] The TPSTF achieved a consensus supporting the application of the three pivotal supplier (TPS) test to the Regulation Market, provided that three adjustments to the rules were included, all of which increased margins for regulation units. PJM filed the proposed revisions on October 1, 2008.[11] A number of parties filed comments, including the MMU on October 20, 2008.[12] The MMU supported the consensus but requested that the Commission direct the MMU to report on the three adjustments to the rules: increasing the current $7.50 adder to cost based offers to $12; modifying the calculation of opportunity costs to use the lower of cost based or price based offers as the reference; and eliminating the netting of revenues from the Regulation Market from make whole balancing operating reserve payments. The Commission, in accepting PJM's filing on November 26, 2008, directed the Market Monitoring Unit to prepare a report due on November 26, 2009.[13]

10 See PJM 2007 Strategic Report at 65 (April 2, 2007). This report is posted on PJM's Website at: http://www2.pjm.com/documents/downloads/strategic-responses/report/20070402-pjm-strategic-report.pdf.

11 PJM submitted its initial filing in FERC Docket No. ER09-13-000.

12 Comments and Motion for Leave to Intervene of the Independent Market Monitor for PJM, Docket No. ER09-13-000. These comments are posted on the Monitoring Analytics' Website at http://www.monitoringanalytics.com.

13 *PJM Interconnection, L.L.C.*, 125 FERC ¶ 61,231, at P 18 (2008).

On December 1, 2008, the three pivotal supplier test was implemented in the Regulation Market to address the identified market power problems. The one month of data for December 2008, is inadequate to permit a meaningful assessment of the impact of the modifications on the PJM Regulation Market.

The implementation of the three pivotal supplier 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. This more flexible and real-time approach to mitigation represents an improvement over the approach to mitigation which had been in place from August 2005 through November 2008 which required cost based offers from the two dominant suppliers at all times. The three pivotal supplier approach to mitigation also represents an improvement over prior methods of simply defining the market to be noncompetitive and limiting all offers to cost based offers. The real-time approach recognizes that at times the market is structurally competitive and therefore no mitigation is required, that at times the market is not structurally competitive and mitigation is required, and that at times generation owners other than the designated, two dominant suppliers may have structural market power that requires mitigation. The MMU also recommends that the overall $100 regulation offer cap remain in effect. The retention of an overall offer cap together with a real-time, three pivotal supplier test for market structure is identical to PJM's current practice in the Energy Market.

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. Prices for synchronized reserve in the RFC Synchronized Reserve Zone and in the Southern Synchronized Reserve Zone are market-clearing prices determined by the supply curve and the administratively defined demand. The cost based synchronized reserve offers are defined to be the unit specific incremental cost of providing synchronized reserve plus a margin of $7.50 per MWh plus lost opportunity cost calculated by PJM.

The issue of Tier 2 synchronized reserve purchases after market clearing began in the last quarter of 2007. Beginning in October and increasing substantially in November and December 2007, there was an increase in the amount of combustion turbine, synchronized condenser MW added by PJM market operations to the Synchronized Reserve Market after market clearing.

In 2008 PJM continued to rely on non-economic, out of market Tier 2 resources added to the resources procured in the synchronized reserve market. Tier 2 synchronized reserve added after the market cleared accounted for approximately 44 percent of total Tier 2 synchronized reserve purchased in 2008. In September, PJM attempted to address this issue by improving the forecast of Tier 1. PJM added a second Tier 1 estimate performed 30 minutes prior to the operating hour. This did not succeed in reducing the amount of Tier 2 added after market clearing.

In December, a significant increase in the amount of estimated Tier 1 reduced the amount of Tier 2 needed to meet the required synchronized reserve. The increase in the amount of estimated Tier 1 appears to have been the result of a mistake in identifying available Tier 1 resources prior to December. The increase in Tier 1 resources did not reduce the amount of Tier 2 synchronized reserve added to the synchronized reserve market after market clearing. In December, the amount of Tier 2 cleared fell substantially, while the proportion of synchronized reserve added out of market increased significantly.

The continued reliance on out of market purchases indicates that the Synchronized Reserve Market is not functioning to coordinate supply and demand in a way consistent with the need identified for these reserves in real time by PJM operations. It is clear that, in actual operations, PJM dispatch identifies a need for more Tier 2 synchronized reserve, or differently located synchronized reserve, than is being forecast and scheduled through the Tier 2 Synchronized Reserve Market. It is clear that there is a difference in the calculation of the need for Tier 2 synchronized reserves in the Mid-Atlantic subzone between the market solution and the operators. The reason remains under investigation.

The MMU concludes that the DASR Market is not structurally competitive, based on the results in 2008. The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test. The MMU also concludes that the DASR Market results were competitive in 2008.

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.

PJM should continue to consider whether additional ancillary service markets need to be defined in order to ensure that the market is compensating suppliers for services when appropriate.

Overall, the MMU concludes that the Regulation Market's results cannot be determined to have been competitive or to have been noncompetitive, although the implementation of the three pivotal supplier test in the Regulation Market on December 1 is expected to improve the results. The MMU concludes that the Synchronized Reserve Markets' results were competitive and that the differences between the market demand and the operational demand for Synchronized Reserves need to be addressed. The MMU concludes that the DASR Market's results were competitive.

Regulation Market

Market Structure

The market structure of the 2008 PJM Regulation Market remained similar to the market structure of the 2007 Regulation Market. DSR participation was introduced in 2006, but demand-side resources have not yet qualified or made offers in the Regulation Market.

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 assigned regulation or 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 software.) 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.

The average eligible regulation supply-to-requirement ratio in the PJM Regulation Market during 2008 was 2.39. 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 *2008 State of the Market Report* 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.[14] During 2008 the PJM regulation requirements ranged from 523 MW to 1,329 MW. The average required regulation was 922 MW (Table 6-1).

Table 6-1 PJM Regulation Market Required MW and Ratio of Supply to Requirement

Period Type	Average Required Regulation (MW)	Ratio of Supply to Requirement
All of 2008	922	2.39
Winter	960	2.52
Spring	834	2.44
Summer	1064	2.19
Fall	815	2.44
August through December Off Peak	665	2.87
August through December On Peak	881	2.43

Market Concentration

Market Structure Definitions

The market structure analysis follows the FERC logic specified in the AEP Order.[15] The logic of the delivered price test is followed by calculating market share, HHI and pivotal supplier metrics for each market configuration.[16] The analysis here includes a broader definition of the relevant competitive offers, defined as those offered and eligible units that could provide regulation at less than, or equal to, 1.5 times the clearing price. In addition, the analysis here includes the result of the three pivotal supplier test. In all cases, regulation must be both offered and eligible in an hour in order for it to be part of the market. This is termed economic capacity under the delivered price test.

The delivered price test may also be applied using available economic capacity, defined as gross supply by participants net of their load obligation. The fact that suppliers have load obligations may affect their incentives to exercise market power although not unambiguously. However, as the amount of load that will be served by the integrated utilities in the future is unknown given the

14 See Reliability*First* Corporation <http://www.rfirst.org/> (1 KB).
15 107 FERC ¶ 61,018 (2004) (AEP Order) and 108 FERC ¶ 61,026 (2004) (AEP Order on Rehearing).
16 AEP Order at 105 *et seq*.

unknown extent of retail competition, a reasonable approach is to evaluate the entire regulation supply, or economic capacity, as is done here.

The FERC's AEP Order indicates that failure of any one of the specified tests is adequate for a showing of market power including tests based on market concentration, market share and pivotal supplier analyses. The analysis presented here goes further in order to analyze the significance of excess supply. The MMU applies the pivotal supplier test using three pivotal suppliers. In addition, when there are hours with three pivotal suppliers, the analysis also examines the frequency with which individual generation owners are in the pivotal group. If the hours that fail a pivotal supplier test have the same pivotal supplier(s) for a significant proportion of the hours, that information can be used to identify dominant suppliers.

The pivotal supplier test represents an analytical approach to the issue of excess supply. Excess supply, by itself, is not adequate to ensure a competitive outcome. A monopolist could have substantial excess supply, but the monopolist would not be expected to change its market behavior as a result. The same logic applies to a small group of dominant suppliers. However, if there is adequate supply without the three dominant suppliers to meet the demand, then the market structure can reasonably be deemed competitive.

PJM Regulation Market

During 2008 the PJM Regulation Market total capability was 7,326 MW.[17] 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 2008 the average daily offer level was 4,983 MW or 68 percent of total capability while the average hourly eligible offer level was 2,183 MW or 30 percent of total capability. In 2008 the average hourly eligible offer level was 44 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 6-2 shows capability, daily offer and average hourly eligible MW for all hours as well as for off-peak and on-peak hours.

Table 6-2 PJM regulation capability, daily offer and hourly eligible: Calendar year 2008

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	7,326	4,983	68%	2,183	30%
Off Peak	7,326	NA	NA	1,936	26%
On Peak	7,326	NA	NA	2,481	34%

The ratio of the hourly eligible regulation supply to the hourly regulation requirement averaged 2.39 for PJM during 2008. When this ratio equals 1.0, it indicates that offered supply exactly equals demand for the referenced time period.

17 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.

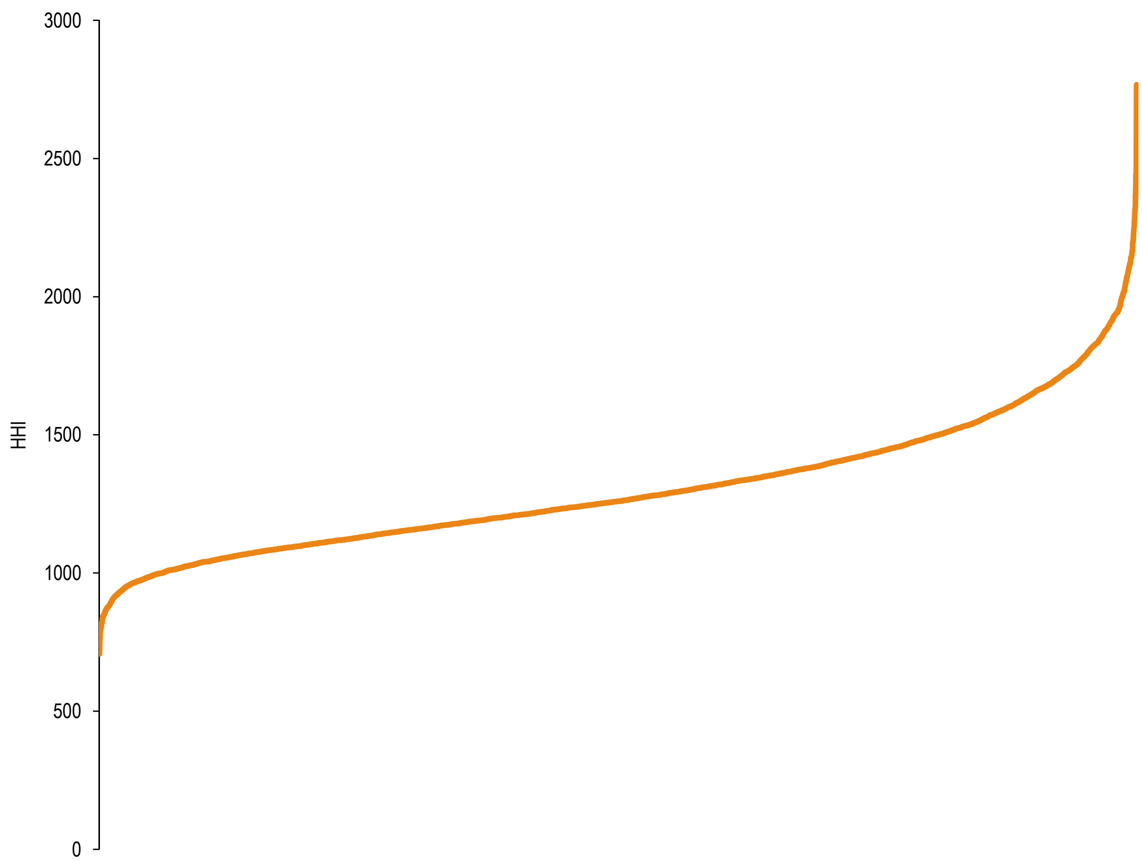
Hourly HHI values were calculated based on cleared regulation. In 2008 HHI values ranged from a maximum of 2767 to a minimum of 707, with a load weighted average value of 1291, which is categorized as moderately concentrated by the FERC definitions. Table 0-3 summarizes the 2008 PJM Regulation Market HHIs and includes HHIs separately for the periods before and after August 2008 to show the impact of the reduction in required regulation.

Table 6-3 PJM cleared regulation HHI: Calendar year 2008

Market Type	Minimum HHI	Load-Weighted Average HHI	Maximum HHI
Cleared Regulation, 2008	707	1290	2767
Cleared Regulation, January through July	707	1226	2767
Cleared Regulation, August through December	736	1397	2480

The PJM Regulation Market exhibited consistent moderate market concentration with about 5.9 percent of the periods with an HHI less than 1000 and about 4.7 percent of the periods with an HHI greater than 1800. See the HHI distribution curve in Figure 6-1.

Figure 6-1 PJM Regulation Market HHI distribution: Calendar year 2008



The largest hourly market share for cleared regulation was 49 percent, and 63 percent of all hours had a maximum market share greater than 20 percent. Although most hours had a market participant with a market share greater than 20 percent, the highest annual average hourly market share by a company was 17.3 percent. The top four annual average hourly market shares for cleared regulation in 2008 are listed in Table 6-4.

Table 6-4 Highest annual average hourly Regulation Market shares: Calendar year 2008

Company Market Share Rank	Cleared Regulation Top Market Shares
1	17%
2	14%
3	10%
4	9%

In 2008, 83 percent of hours failed the three pivotal supplier test. This means that for 83 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 89 percent of three pivotal hours. A second company was pivotal in 85 percent of the three pivotal hours. A third company was pivotal in 61 percent of three pivotal hours. Table 6-5 includes a monthly summary of three pivotal supplier results.

Table 6-5 Regulation market monthly three pivotal supplier results: Calendar year 2008

Month	Hours With Three Pivotal Suppliers
Jan	84%
Feb	83%
Mar	89%
Apr	88%
May	97%
Jun	77%
Jul	75%
Aug	80%
Sep	74%
Oct	89%
Nov	59%
Dec	92%

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 2008.

The MMU concludes from these results that the PJM Regulation Market in 2008 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, 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.[18] 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 cost based offers of all offered and eligible regulating resources in ascending total offer price order; it does the same for synchronized reserve and simultaneously 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. Units are assigned to regulate in ascending merit order by price until the required regulation is satisfied. The resulting assignments are evaluated to see which if any of the owning companies are pivotal. Pivotal companies will have their resources offer capped at the lesser of their cost based or price based offer. The generating units of companies which are not pivotal will then have their offer reset to their price based offer and the market is cleared.[19] The Regulation Market price that results is the RMCP and the unit that sets this price is the marginal unit.

18 PJM estimates the opportunity cost for units providing regulation based on a forecast of locational marginal price (LMP) for the upcoming hour. In September 2008, 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 LOC calculator now uses the lesser of the available price based energy schedule or the most expensive available cost based energy schedule.

19 See PJM, "Manual-11: Scheduling Operations," Revision 38 (Redline), Regulation Market Clearing, (January 15, 2009) (accessed February 23, 2009), p. 37.

In 2008, offers from some regulation suppliers exceeded the competitive level. Based on the MMU's estimates of unit specific cost data, 18 percent of marginal unit daily offers exceeded marginal costs. The competitive offer level for regulation, as for any other market, is the marginal cost of providing regulation. For the PJM Regulation Market, the marginal cost has been defined as the calculated cost plus a margin of $7.50 per MWh, through November 2008. From January through November 2008, the cost of providing regulation was not provided by suppliers. The MMU had long recommended that the provision of such data be required and although PJM systems were created to allow the provision of cost data, provision of the data had not been mandatory. In December 2008, with the introduction of the three pivotal supplier test in the regulation market, suppliers of regulation are required to provide cost data if their cost based offer exceeds $12/MWh.

Market Performance

Price

Figure 6-2 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 multiplied by the unit's assigned regulating capability, or the unit's regulation offer multiplied by its assigned regulating capability plus the individual unit's real-time opportunity cost.[20]

From January through November 2008, offers at levels greater than the competitive level set the clearing price for regulation in 18 percent of hours.[21] In eight percent of hours offers were greater than $5.00 per MW above the competitive level; in seven percent of hours offers were greater than $10.00 per MWh above the competitive level; and in one percent of hours the marginal unit offer was greater than $15.00 per MWh above the competitive level. To put these results in context, the load weighted, average offer price for all marginal units in the PJM Regulation Market during 2008 was $11.94, so an additional $5.00 per MWh is a markup of approximately 42 percent. These results mean that the MMU cannot conclude that the Regulation Market results were competitive in 2008 or that the Regulation Market results were noncompetitive. The absence of a definitive conclusion is a result of the fact that the cost data are based on MMU estimates rather than data submitted by market participants. The MMU supports the change to the regulation market rules on December 1, 2008 requiring participants to submit the cost of regulation consistent with the definitions in PJM's "Cost Development Guidelines."[22]

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 RMCP 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 RMCP times the unit's assigned regulating capability, or the unit's regulation offer times its assigned regulating capability plus the opportunity cost that the unit has incurred. Although most

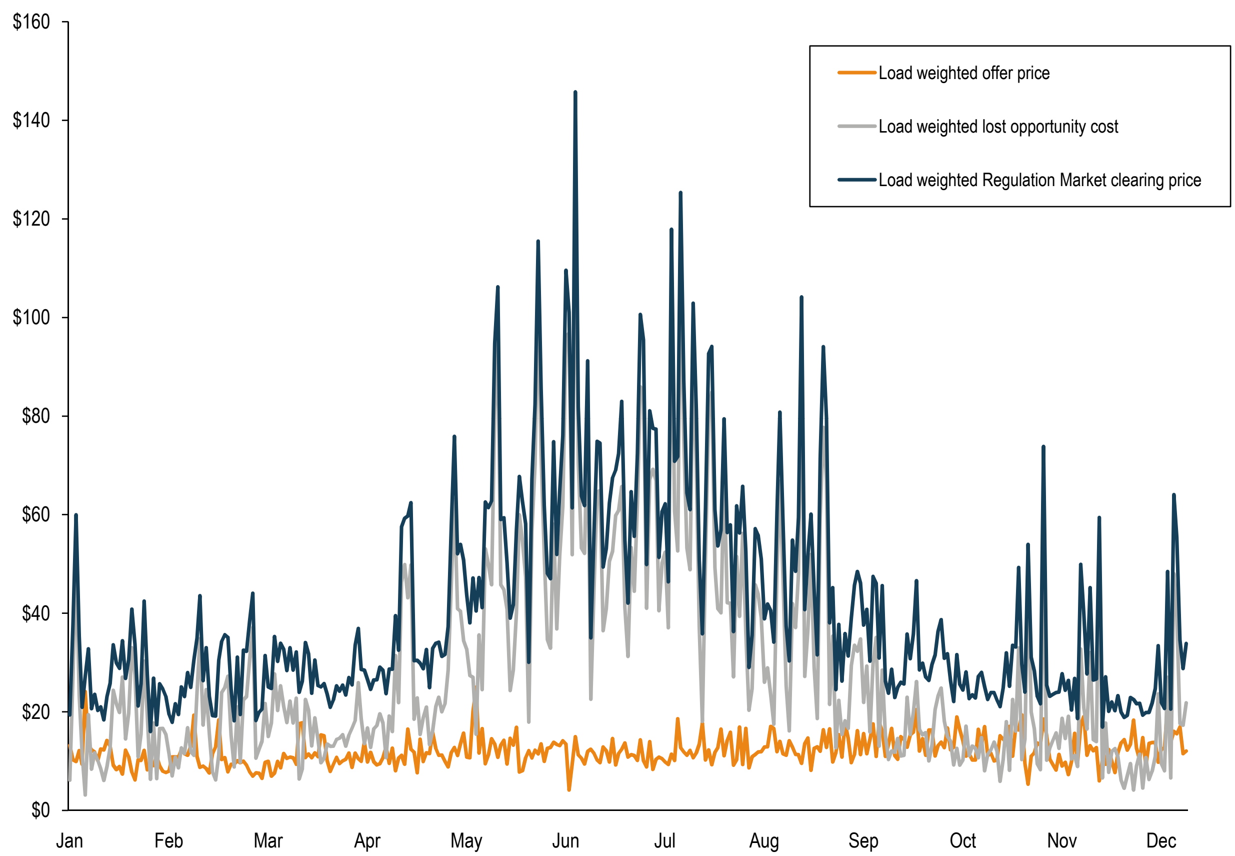
20 See PJM. "Manual 28: Operating Agreement, Accounting," Revision 41, Section 4, "Regulation Credits" (November 1, 2008), pp. 27-28. PJM uses estimated opportunity cost to clear the market and real-time opportunity cost to compensate generators that provide regulation and synchronized reserve. Real-time opportunity cost is calculated using real-time LMP.

21 The percent of hours in which the offer of the marginal unit exceeded marginal cost is slightly less than the percent of offers of marginal units exceeding marginal cost because there can be multiple marginal units in an hour.

22 PJM M-15, Cost Development Guidelines, Rev 9, January 23, 2009, Section 4, Fuel Cost Guidelines, Section 5, Operating and Maintenance Cost Guidelines, and Section 6, Start Cost Guidelines. Pgs. 11-34

units are paid RMCP times their assigned regulation MWh, a substantial portion of the RMCP is the LOC, based on forecast LMP calculated for the marginal unit during market clearing. This means that a substantial portion of the total cost of regulation is determined by LOC. As shown in Figure 6-2, more than half of the regulation price is the LOC of the marginal unit. The balance of the RMCP is the unit's regulation offer. The load weighted, average offer of the marginal unit for the PJM Regulation Market during 2008 was $11.94 per MWh. The load weighted, average LOC of the marginal unit for the PJM Regulation Market during 2008 was $30.59. In the PJM Regulation Market the marginal unit LOC averaged 72 percent of the RMCP.

Figure 6-2 PJM Regulation Market daily average market-clearing price, lost opportunity cost and offer price (Dollars per MWh): Calendar year 2008



On a shorter term basis, regulation prices follow daily and weekly patterns. The supply of regulation is most plentiful between 0600 and 2300 EPT, Monday through Friday.

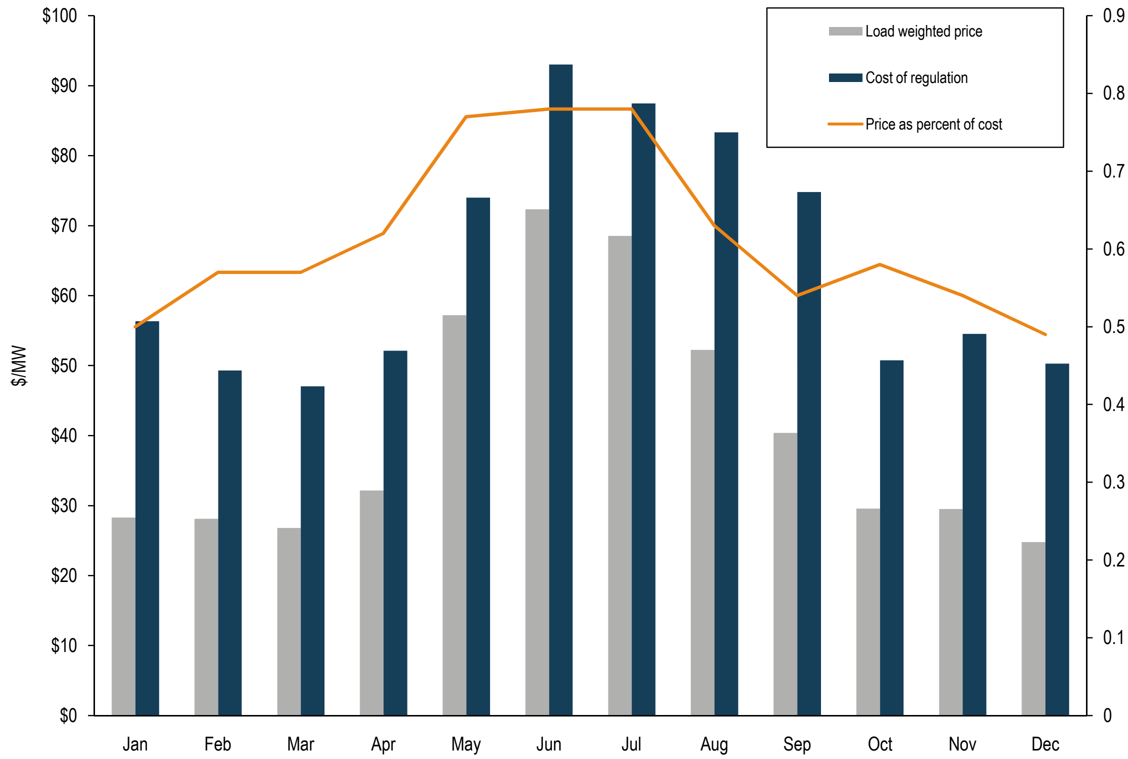
During weekends and North American Electric Reliability Council (NERC) holidays, and weekdays between the hour ending at 2300 until the hour ending at 0800 (i.e., the off-peak hours), fewer steam generators are running and available to regulate. At times, units must be kept running for regulation that are not economic for energy, resulting in an increase in the LOC portion of the clearing price. At other times, expensive combustion turbine generators must be started to meet regulation requirements. Although the regulation requirement is a function of reliability concerns, lower off-peak load allowed PJM to decrease the off-peak regulation requirement in August 2008, thus aligning demand with supply and moderating prices.

Figure 6-3 shows the level of demand for regulation by month in 2008 and the corresponding level of regulation price. The data show a correlation between price and demand. In 2008, the August reduction in the regulation requirement for off-peak hours resulted in a corresponding reduction in regulation demand and price.

Figure 6-3 Monthly average regulation demand (required) vs. price: Calendar year 2008

As with all ancillary services, the total cost of the service per MWh will exceed the price per MWh because some regulation is procured out of the market or because there are adjustments to unit specific LOC 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 6-4 compares the regulation cost per MWh (price plus settled lost opportunity costs) with the regulation clearing price to show the difference between the price of regulation and the cost of regulation.

Figure 6-4 Monthly load weighted, average regulation cost and price: Calendar year 2008



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

Table 6-6 Total regulation charges: Calendar year 2008

Month	Scheduled Regulation MWh	Total Regulation Charges	Weighted Average Regulation Market Price ($/MWh)	Cost of Regulation ($/MWh)
Jan	739,736	$41,680,277	$28.29	$56.34
Feb	685,256	$33,792,512	$28.16	$49.31
Mar	659,679	$31,036,079	$26.76	$47.04
Apr	587,950	$30,640,949	$32.12	$52.11
May	593,392	$43,908,281	$57.43	$74.00
Jun	767,808	$71,423,112	$72.51	$93.03
Jul	857,979	$75,035,751	$69.41	$87.46
Aug	727,153	$60,569,059	$52.21	$83.30
Sep	622,563	$46,572,848	$40.38	$74.81
Oct	576,303	$30,251,416	$29.58	$52.49
Nov	598,079	$32,617,280	$29.52	$54.54
Dec	677,526	$34,066,767	$24.79	$50.28
Total	8,093,424	$521,485,646	$42.09	$64.43

For 2008, the load weighted, average regulation price was $42.09 per MWh. The average regulation cost was $64.43 per MWh. The difference between the Regulation Market price and the actual cost of regulation remained significant in 2008. The cost of regulation was 53 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.

Synchronized Reserve Market

Market Structure

In 2008, the PJM Synchronized Reserve Market structure remained unchanged following its restructuring in 2007. Reliability requirements for the RFC Synchronized Reserve Zone are set by the Reliability*First* Corporation. The Southern Region's Synchronized Reserve Market remains a separate market. It falls under the reliability requirements of SERC and is referred to as the Southern Synchronized Reserve Zone. 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 in the PJM Mid-Atlantic subzone of the RFC. This subzone is defined as the RFC Synchronized Reserve Zone exclusive of the AP, AE, Dayton, Duquesne, and ComEd zones.[23] Therefore PJM's market must clear enough Tier 2 synchronized reserve in the Mid-Atlantic (Eastern) subzone of the RFC Synchronized Reserve Market to ensure that the Mid-Atlantic locational

23 PJM M-11, Scheduling Operations, Rev 37, November 24, 2008, pg. 44.

synchronized reserve requirement of 1,150 MW is met, after accounting for available Tier 1 supply. This results in a separate Mid-Atlantic subzone clearing price.

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.[24] 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 a market for Tier 2 synchronized reserves. This market is termed 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; 60 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 clearing price is determined at least 30 minutes prior to the start of the hour. This Tier 2 price is equivalent to the merit-order price of the highest-priced, Tier 2 resource needed to meet the demand for synchronized reserve requirements, the marginal

24 See PJM. "Manual 11: Scheduling Operations," Revision 37 (November 24, 2008), p. 41.

unit, based on the simultaneous clearing of the Regulation Market and the Synchronized Reserve Market.[25]

The synchronized reserve offer price submitted for a unit can be no greater than the unit's incremental operating and maintenance cost plus a $7.50 per MWh margin.[26, 27] 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. LOC is calculated by PJM based on forecast LMPs and generation schedules from the unit dispatch system. LOC 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 LOC and the cost of energy use incurred.

The Tier 2 Synchronized Reserve Market in each of PJM's synchronized reserve areas is cleared on cost based offers because the structural conditions for competition do not exist. The market structure issue can be even more severe when the Synchronized Reserve Market becomes local because of transmission constraints.

For the RFC Synchronized Reserve Zone during 2008, the offered and eligible excess supply ratio was 2.01. Within the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone, the offered and eligible excess supply ratio was 1.41.[28] 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 after careful review to ensure appropriate 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, recognizing potential deliverability issues.[29]

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 through May 9, 2008 was 1,300 MW. From May 10, 2008 through December 31, 2008 the requirement was 1,305 MW.[30] Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency.

25 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.

26 See PJM. "Manual 11: Scheduling Operations," Revision 37 (November 24, 2008), p. 43.

27 See PJM. "Manual 15: Cost Development Guidelines," Revision 8 (October 16, 2007), p. 34.

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

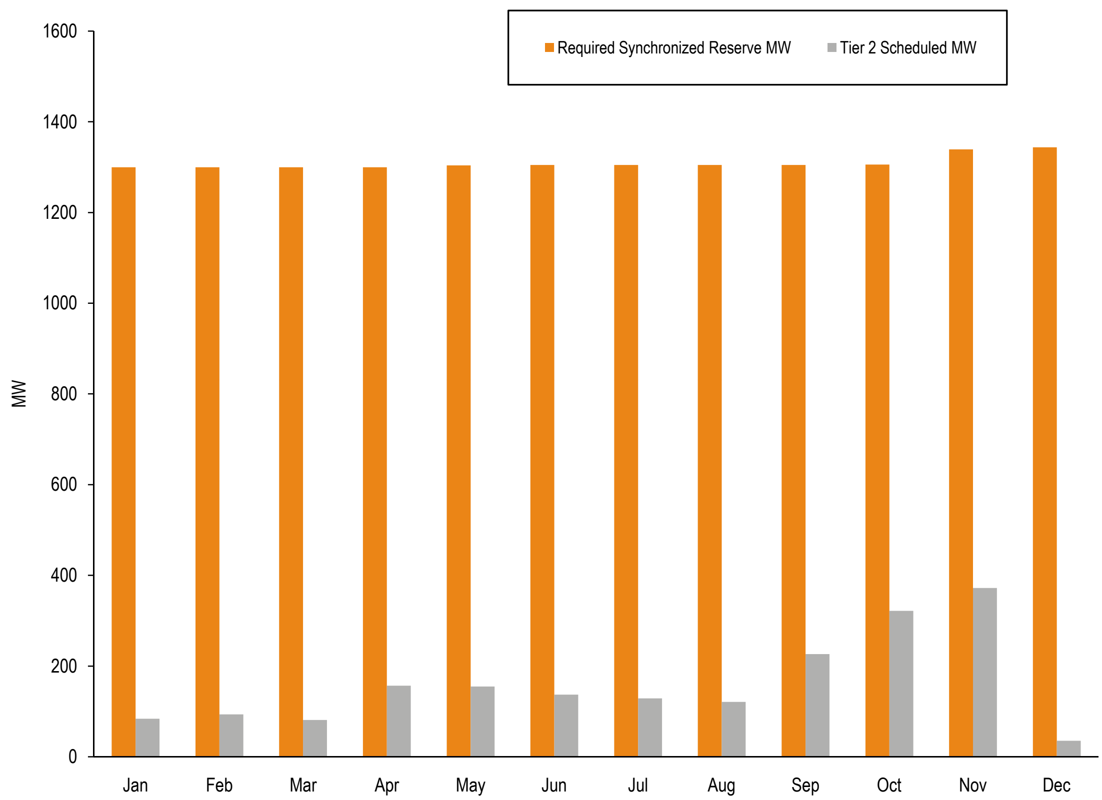
29 See PJM. "Manual 10: Pre-Scheduling Operations," Revision 23 (January 2, 2008), p. 17.

30 The reasons for this increase are not known.

Such a condition occurred on February 2 when the Synchronized Reserve requirement was set at 2,300 MW. For 2008, the average RFC Zone Tier 2 required was 1,310 MW.

Figure 6-5 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during 2008 for the RFC Synchronized Reserve Market. Figure 6-5 and Figure 6-6 below show that the amount of Tier 2 synchronized reserve scheduled for the RFC Zone and the Mid-Atlantic Subzone increased in September, October and November and then decreased sharply in December.

Figure 6-5 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: Calendar year 2008



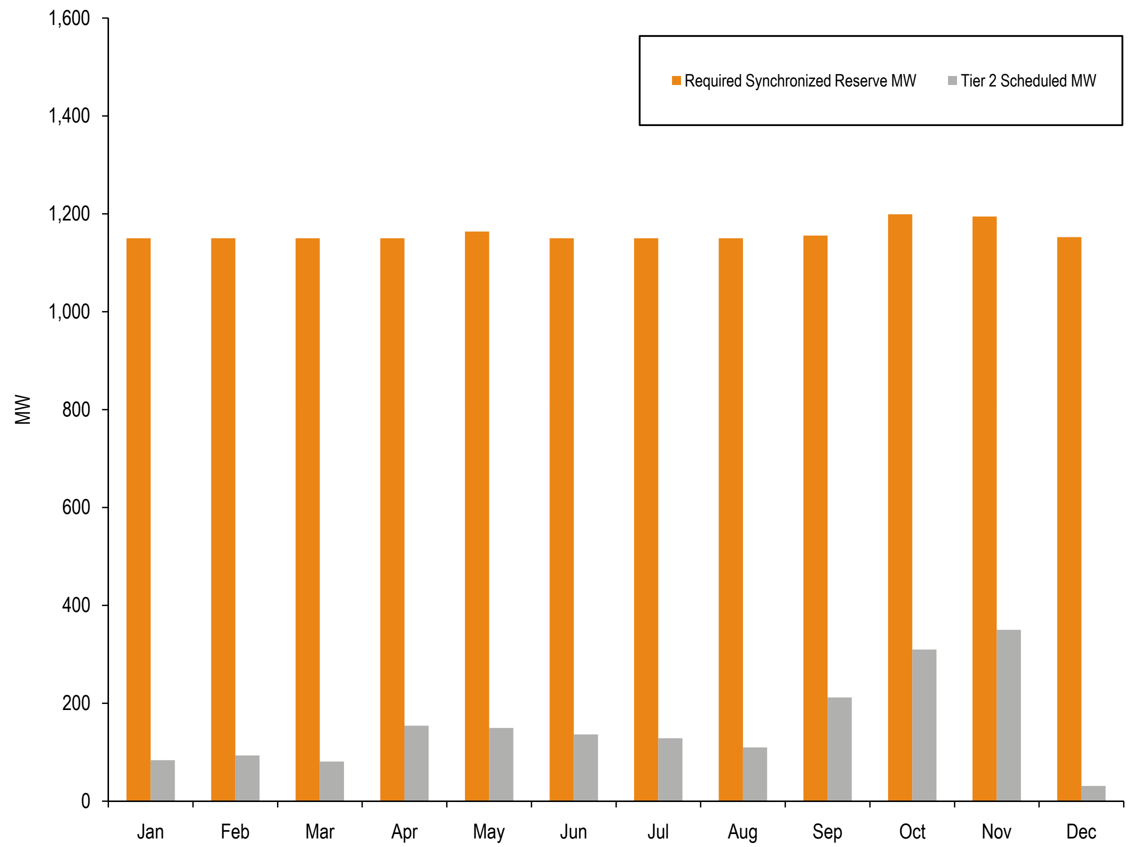
The RFC Synchronized Reserve Zone is large and some available Tier 1 must be physically located in the Mid-Atlantic Subzone as a result of transmission limits between the western and eastern portions of the zone. PJM calculates the transfer capability of these transmission facilities. The calculation 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.[31]

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

31 See PJM. "Manual 11: Scheduling Operations," Revision 37 (October 24, 2008,), p. 48.

Reserve Zone generally exceeds the total synchronized reserve requirement in the west. In 2008, the RFC Synchronized Reserve Zone cleared a Tier 2 Synchronized Reserve Market in 5 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 for the Mid-Atlantic Subzone. The Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone cleared a separate Tier 2 market in 62 percent of all hours. Figure 6-6 compares the required synchronized reserve MW to the scheduled Tier 2 MW for the Mid-Atlantic Subzone only.

Figure 6-6 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: Calendar year 2008



The actual synchronized reserve requirement for the Mid-Atlantic Subzone for February through December 2008 was usually 1,150 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 2,300 MW on February 2, 2008. Throughout all of 2008, the average synchronized reserve required MW in the Mid-Atlantic Subzone was 1,160 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.

A comparison of Figure 6-5 and Figure 6-6 illustrates that 98.9 percent of Tier 2 Synchronized Reserve Market MW are Mid-Atlantic Subzone, Synchronized Reserve Market MW.

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.[32] 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. On average, the hourly synchronized reserve requirement in Dominion was 1.5 MW.

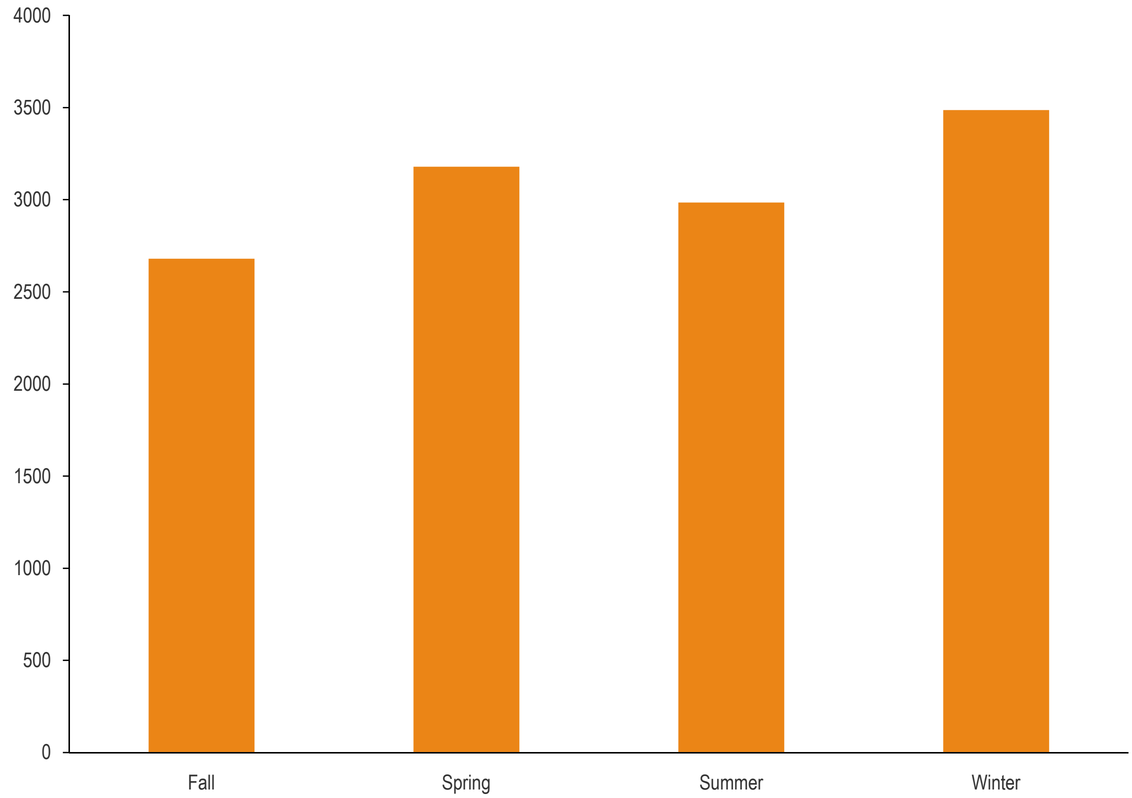
Market Concentration

The Tier 2 Synchronized Reserve Market is the only Synchronized Reserve Market cleared by PJM. Although the RFC Tier 2 Synchronized Reserve Market was less concentrated in 2008 than it had been in 2007, the 2008 RFC Synchronized Reserve Market remains highly concentrated and dominated by a relatively small number of companies. Concentration levels have been reduced as a result of the increased participation of demand-side response in the synchronized reserve market.

The HHI for the Mid-Atlantic Subzone of the 2008 RFC Synchronized Reserve Market was 3106, which is defined as highly concentrated. (See Figure 6-7 which also provides seasonal details.)

32 See PJM. "Manual 11: Scheduling Operations," Revision 37 (November 24, 2008), p. 72.

Figure 6-7 Cleared Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market seasonal HHI: Calendar year 2008



The largest hourly market share was 100 percent and 52 percent of all hours had a maximum market share greater than or equal to 40 percent. In slightly less than one percent of Mid-Atlantic Subzone hours during which a market was cleared between January and December 2008, a single company had 100 percent 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 33 percent. In other words, a single company sold 33 percent of synchronized reserves on average for all hours in which it had market share over the entire year. (See Table 6-7.)

Table 6-7 The Mid-Atlantic Subzone of the PJM RFC Tier 2 Synchronized Reserve Market's cleared market shares: Calendar year 2008

Company Market Share Rank	Cleared Synchronized Reserve: All Units
1	33%
2	32%
3	30%
4	30%
5	29%

The pivotal supplier metric provides an analytical approach to the issue of excess supply.[33] In 2008, 96 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 64 percent of all pivotal hours, a second company was pivotal in 44 percent of all pivotal hours, and a third company was pivotal in 43 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

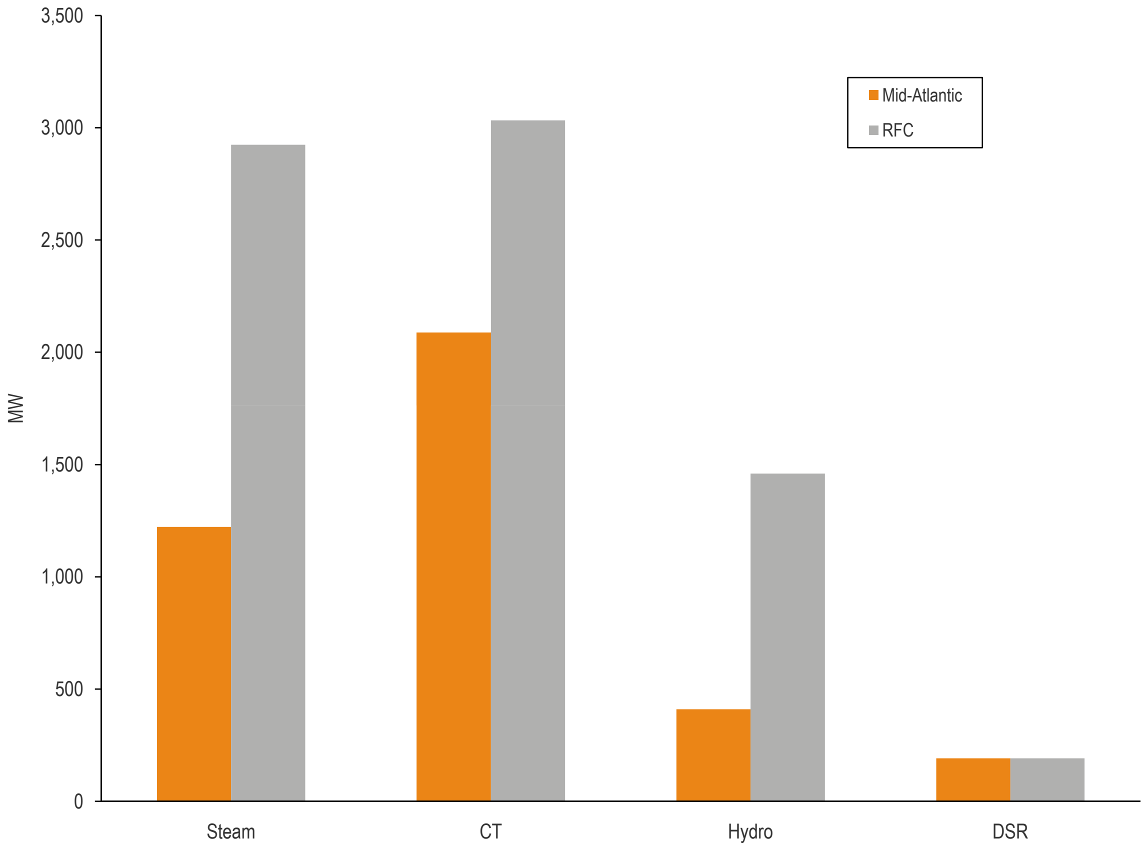
Figure 6-8 shows the daily average hourly offered Tier 2 synchronized reserve MW. For steam units, offered MW are eligible only if the offering unit is running. For that reason, the eligible offer volume shows weekly variability based on off-peak/on-peak operating cycles as well as seasonal variability.

Figure 6-8 Tier 2 synchronized reserve average hourly offer volume (MW): Calendar year 2008

33 See the *2008 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test."

Synchronized reserve is offered by steam, CT, hydroelectric and DSR resources. Figure 6-9 shows average offer MW volume by market and unit type.

Figure 6-9 Average daily Tier 2 synchronized reserve offer by unit type (MW): Calendar year 2008



The MW contribution of DSR resources to the Synchronized Reserve Market remained significant in 2008. The significance of DSR in the Synchronized Reserve Markets is greater than its eligible offer MW as illustrated in Figure 6-9. In 2008, DSR accounted for all cleared Tier 2 synchronized reserves in 27 percent of hours when a synchronized reserve market was cleared. In the hours when all supply was DSR, the unweighted average SRMCP was $2.58. 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.

Market Performance

Price

Figure 6-10 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 Eastern subzone of the PJM 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 6-10 Required Tier 2 synchronized reserve, synchronized reserve market clearing price, and DSR percent of Tier 2

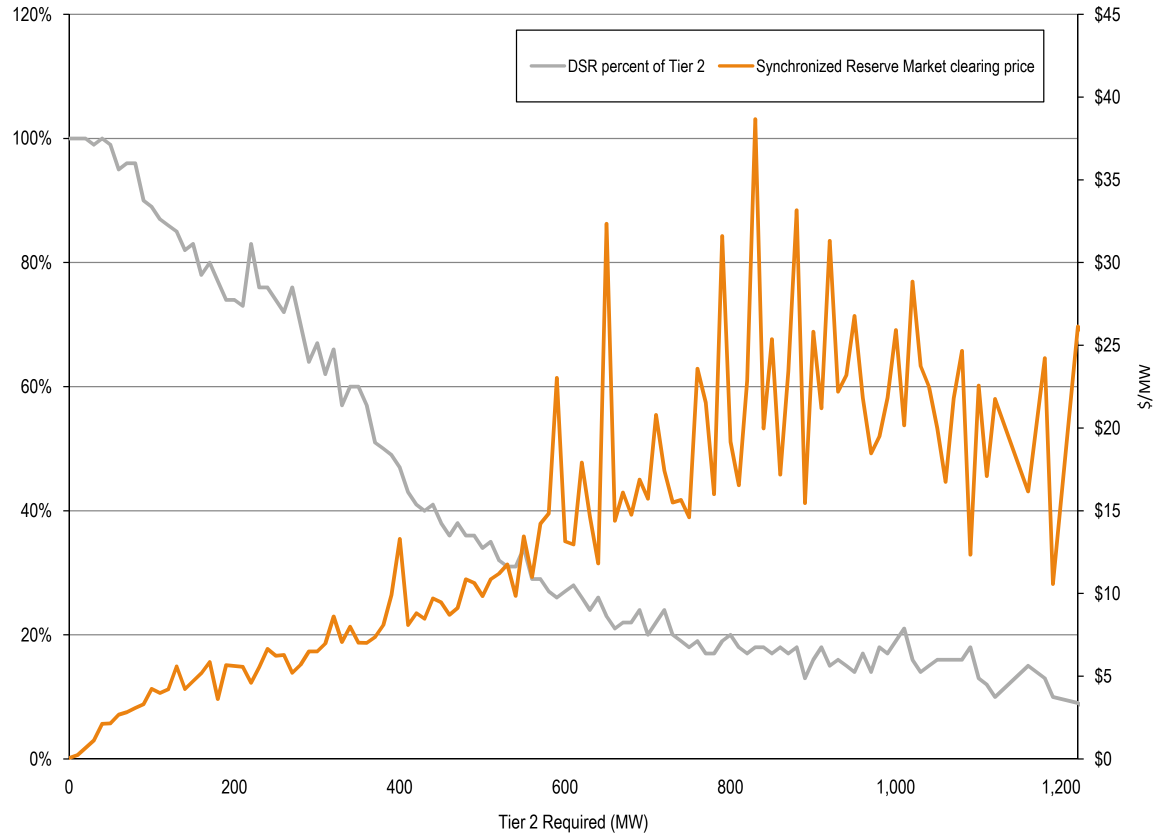


Figure 6-14 shows the load weighted, average Tier 2 price and the cost per MW associated with meeting PJM demand for synchronized reserve. The price of Tier 2 synchronized reserve is called the Synchronized Reserve Market-clearing price (SRMCP). Resources which provide synchronized reserve are paid the higher of the SRMCP or their offer plus their unit specific LOC. The offer plus the unit specific LOC 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 LOC 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 LOC, the result is that PJM's synchronized reserve cost per MWh is higher than the SRMCP.

The RFC Synchronized Reserve Market cleared as a single market 5 percent of all hours in 2008 with a load weighted average $4.94 clearing price. The load weighted, average price for synchronized reserve in the PJM Mid-Atlantic subzone of the RFC Synchronized Reserve Market in 2008 was $10.65 while the corresponding cost of synchronized reserve was $16.43.

Price and Cost

In 2008 PJM continued to rely on non-economic, out of market Tier 2 resources added to the resources procured in the synchronized reserve market. PJM dispatch procured additional Tier 2 reserves to cover anticipated operational needs. This added Tier 2 MW added to the cost of Tier 2 synchronized reserve and has been a significant contributor to total synchronized reserve costs. To improve the accuracy of the forecast Tier 1, PJM added a second Tier 1 estimate performed 30 minutes prior to the operating hour in September. This change appears to have had no impact on Tier 2 MW added after market clearing or on improving the forecasting the amount of Tier 1 available during a spinning event.

In December, a significant increase in the amount of estimated Tier 1 reduced the amount of Tier 2 needed to meet the required synchronized reserve. The increase in the amount of estimated Tier 1 appears to have been the result of a mistake in identifying available Tier 1 resources prior to December. The relationship between Tier 2 required and Tier 1 estimated is shown in Figure 6-11. When Tier 1 estimated increased from a daily average of 370 MW to 1,132 MW on December 1, 2008, the Tier 2 synchronized reserve market dropped from a November average of 350 MW to a December average of 31 MW.

The increase in Tier 1 resources did not reduce the amount of Tier 2 synchronized reserve added to the synchronized reserve market after market clearing. In December, the amount of Tier 2 cleared fell substantially, while the proportion of synchronized reserve added out of market increased significantly. Tier 2 MW added after the market cleared accounted for 44 percent of total Mid-Atlantic subzone synchronized reserve in 2008 and 80 percent in the month of December. Such synchronized reserve MW are not part of the market clearing process so they do not affect the price of synchronized reserve, but they do increase the amount of synchronized reserve purchased for which load-serving entities must pay. (See Figure 6-13.)

Figure 6-11 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated

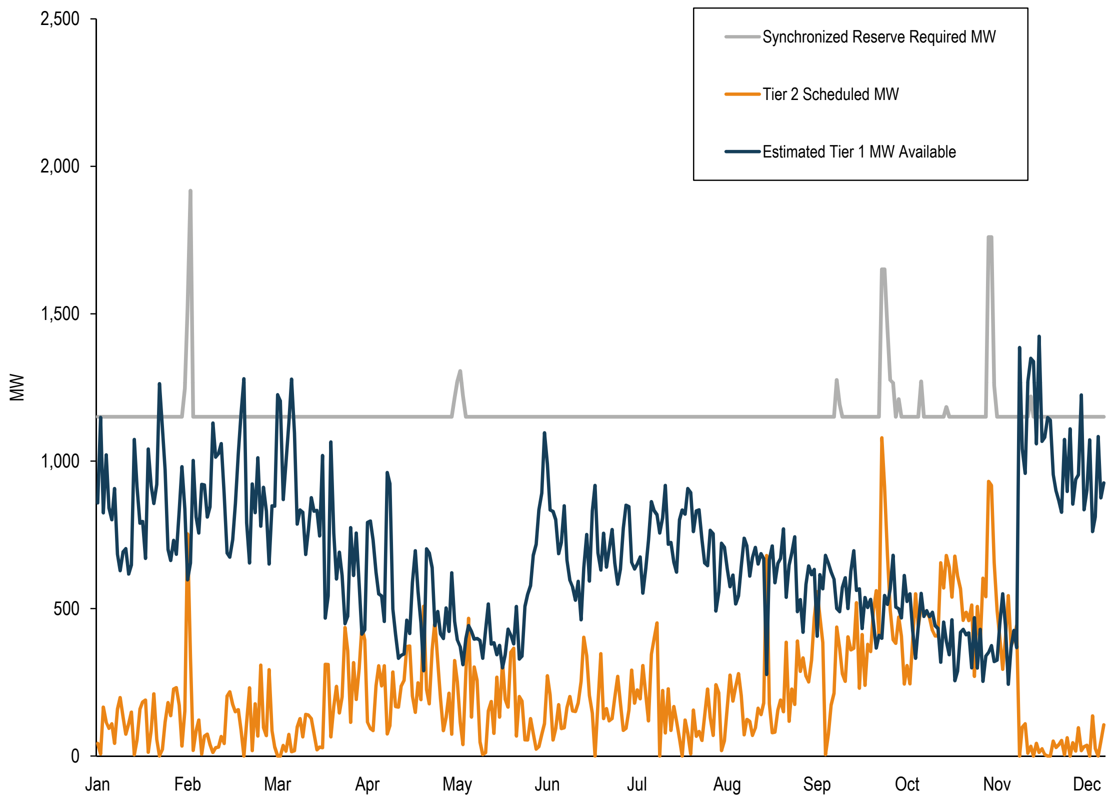
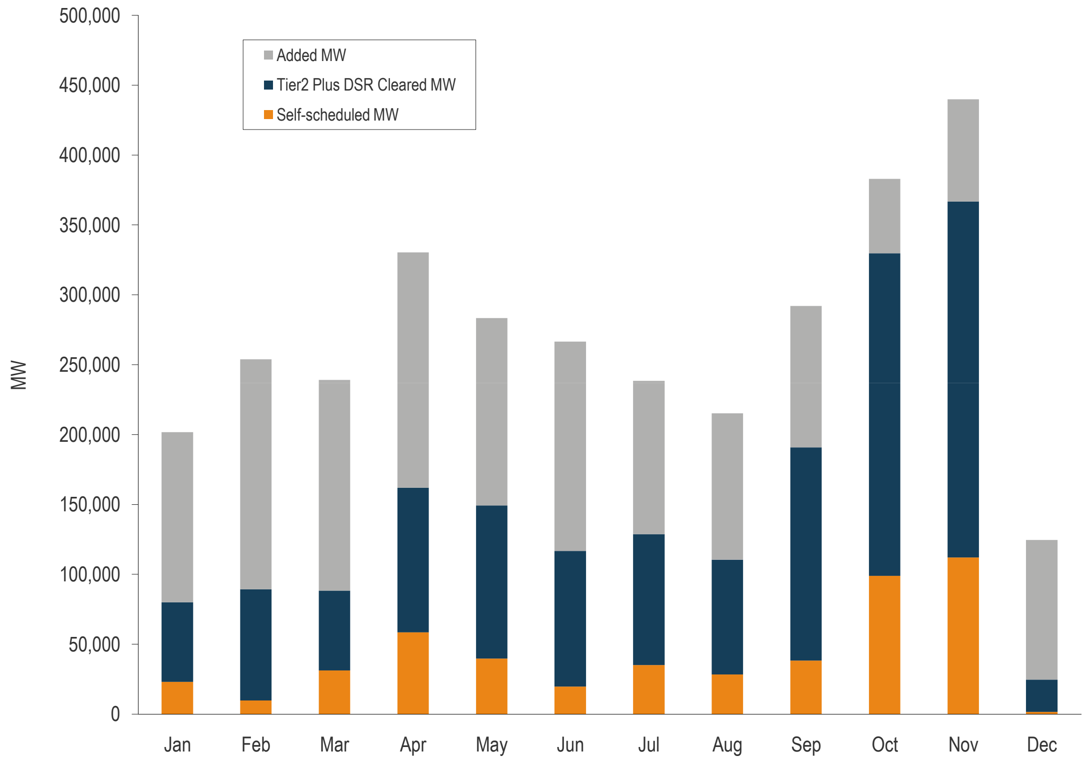


Figure 6-12 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic subzone DSR



The out of market purchases indicate that the Synchronized Reserve Market is not functioning to adequately coordinate supply and demand. (Figure 6-13) The addition of synchronized reserve MW to the Synchronized Reserve Market on an out of market basis means that the clearing price is below the efficient level for the defined market. It is clear that there is a difference in the calculation of the need for Tier 2 synchronized reserves between the market solution and the operators. The reason remains under investigation.

The difference between the Tier 2 Synchronized Reserve Market price and the cost for Tier 2 synchronized reserve in 2008 was approximately the same as it had been in 2007 (Figure 6-14). The difference in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market for 2008 between the monthly load weighted, average price of Tier 2 synchronized reserve and cost of Tier 2 synchronized reserve was $5.82. The cost was 55 percent higher than the price. In 2007 the cost had been 31 percent higher than the price.

Figure 6-13 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic subzone: Calendar year 2008

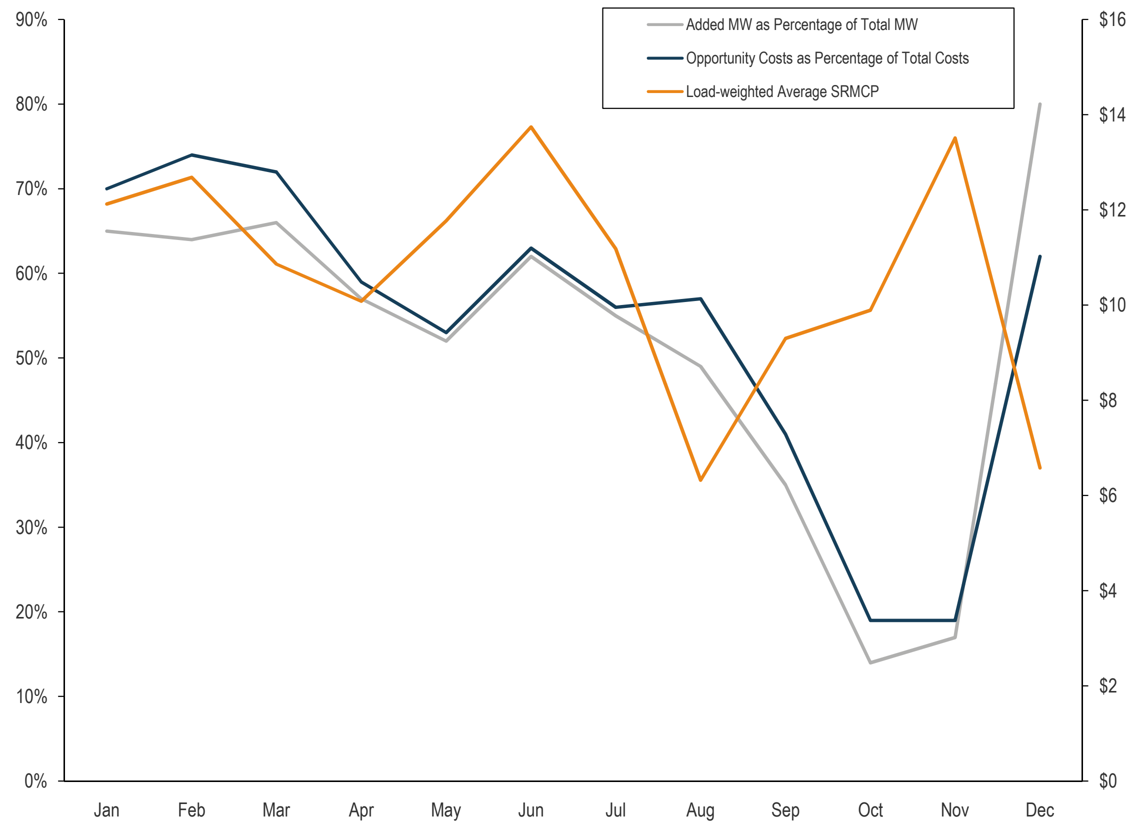
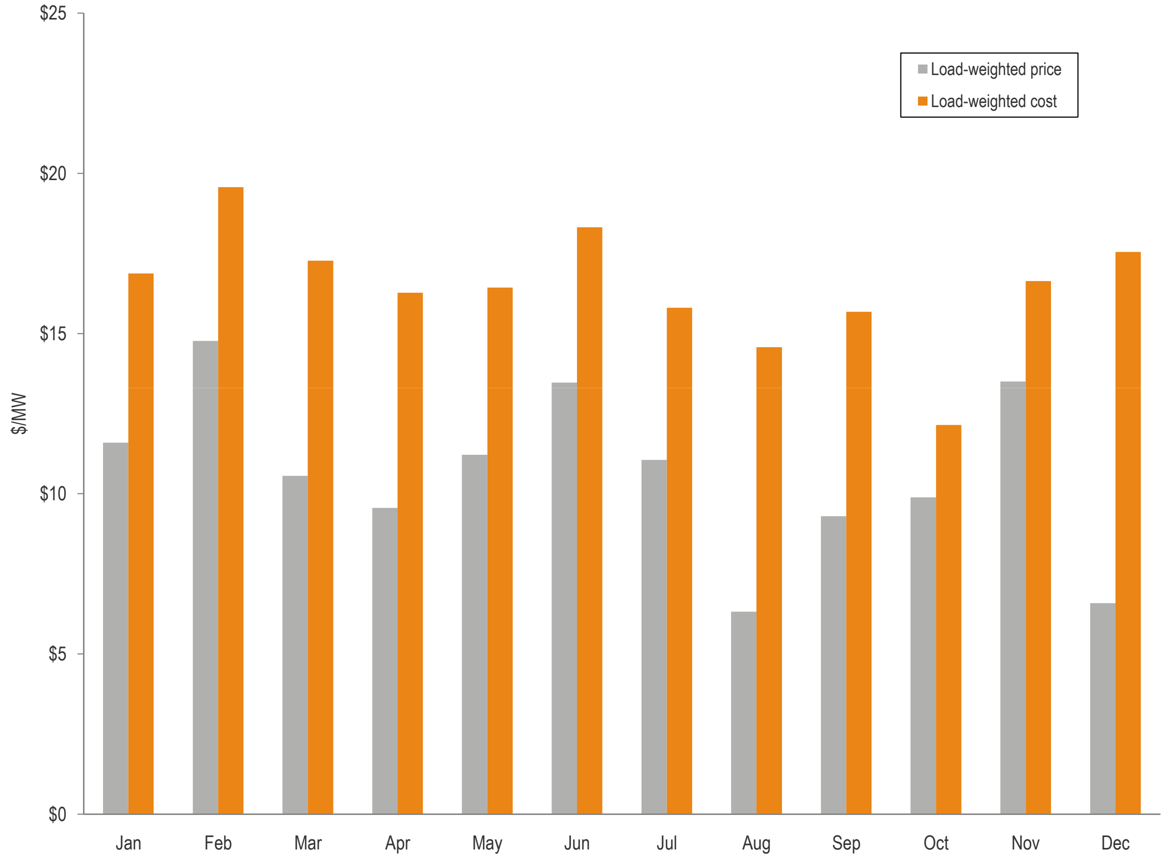


Figure 6-14 Comparison of RFC Tier 2 synchronized reserve price and cost (Dollars per MW): Calendar year 2008



Market Solution and Actual Dispatch of Ancillary Services

The actual dispatch of ancillary services can and does differ from the market solution, in many cases, as a result of legitimate reliability concerns. The result is usually that total costs per MWh (credits/MWh) 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. The MMU attempts to document and categorize deviations from market solutions although there tends to be insufficient PJM documentation. 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 all unit deselection reasons be published in PJM's M-11 Scheduling Operations Manual. The MMU recommends that dispatchers classify the reasons for unit deselection and document all unit deselections.

DSR

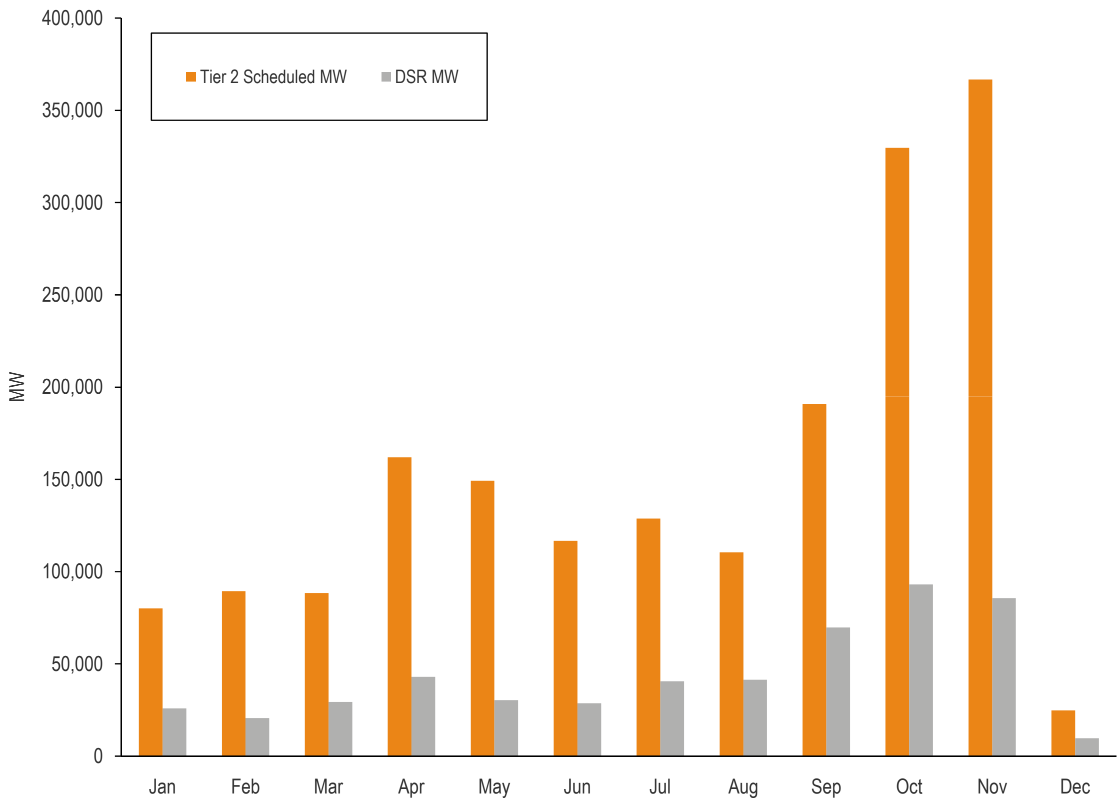
Demand-side resources began participating in the Synchronized Reserve Markets in August 2006. DSR continues to have a significant impact on the Synchronized Reserve Market. In 32 percent of hours where a synchronized reserve market was cleared in the Mid-Atlantic subzone of the RFC (see Table 6-8), all cleared synchronized reserve was DSR synchronized reserve. The clearing price for those hours was significantly lower than the average clearing price overall.

Table 6-8 Average SRMCP when all cleared synchronized reserve is DSR, average SRMCP, and percent of all cleared hours that all cleared synchronized reserve is DSR

Month	Average SRMCP when all cleared synchronized reserve is DSR	Average SRMCP	Percent of cleared hours all synchronized reserve is DSR
Jan	$2.65	$7.09	42%
Feb	$4.03	$7.87	41%
Mar	$3.89	$7.28	45%
Apr	$3.06	$7.33	28%
May	$2.42	$7.73	31%
Jun	$1.91	$9.30	26%
Jul	$1.73	$7.17	35%
Aug	$2.06	$3.47	41%
Sep	$2.48	$6.77	28%
Oct	$2.26	$8.03	17%
Nov	$2.30	$10.71	11%
Dec	$1.17	$2.09	36%

Figure 6-15 shows total monthly synchronized reserve scheduled MW and cleared MW for DSR synchronized reserve. Participation of demand response in the synchronized reserve market remained strong. Not only did more participants offer DSR, but demand response was significantly less expensive than other forms of synchronized reserve. The reason for the lower price of demand resources is twofold. Demand resources typically offer at a lower price, and demand resources do not have lost opportunity costs added to their offer in market clearing. In 32 percent of hours during 2008 in which a Tier 2 Synchronized Reserve Market was cleared for the Mid-Atlantic Subzone, all synchronized reserve was provided by DSR.

Figure 6-15 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: Calendar year 2008



Availability

A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced deficits during 2008.

Day Ahead Scheduling Reserve (DASR)

PJM has a requirement to procure supplemental reserves to ensure that differences in forecasted loads and forced generator outages will not have a negative impact on grid reliability.[34] 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.

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

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the settlement in the RPM case.[35] 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.[36] In the Reliability*First* (RFC) region, reserve requirements are calculated based on historical under forecasted load rates and generator forced outage rates. For 2008 the load forecast error component of this calculation was 2.10 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 2008 the forced outage component of the Day-Ahead Scheduling Reserve was 4.64 percent. For 2008 the Day-Ahead Scheduling Reserve for RFC areas of PJM was 6.75 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 2008 VACAR scheduling reserve was set at 423 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 and co-optimized with the Day-Ahead Energy Market.

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 the first two months of DASR operation there were many units without offers, several units with offers high enough to ensure that they would not clear and some software problems. Since that initial period, the DASR Market has been relatively stable and characterized by low prices.

35 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).
36 PJM Manual 13, Emergency Requirements, Rev 35, 11/07/2008; pp 11-12.

Table 6-9 2008 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices

Month	Average Required MW	Average Cleared MW	Minimum Clearing Price	Maximum Clearing Price	Load Weighted Price	Total Deficit MW	Total Load Reduction MW
Jun	1,622	1,622	$0.00	$7.80	$0.91	0	0
Jul	4,484	4,484	$0.00	$2.00	$0.55	0	0
Aug	6,044	6,044	$0.23	$1.50	$0.36	0	0
Sep	5,162	5,162	$0.14	$1.00	$0.23	0	0
Oct	4,825	4,825	$0.00	$0.22	$0.10	0	0
Nov	5,194	5,194	$0.00	$0.22	$0.09	0	386
Dec	5,633	5,633	$0.00	$0.75	$0.09	0	1,042

For June 2008 through December 2008, the load weighted price of DASR was $0.26. As can be seen from Table 6-9, DASR prices declined in the last three months of 2008. DSR began to offer and clear the market in November and became significant in December.

The DASR Market in 2008 had three pivotal suppliers in a monthly average of 45 percent of all hours. Although the DASR Market was structurally non competitive for a substantial portion of all hours, the proportion of hours in which there were three pivotal suppliers declined in November and December (see Table 6-10).

Table 6-10 2008 PJM, Day-Ahead Scheduling Reserve Market pivotal supplier results

Month	Hours With Three Pivotal Suppliers
Jun	31%
Jul	38%
Aug	54%
Sep	80%
Oct	65%
Nov	23%
Dec	23%

In December, about 5.8 percent of all units engaged in economic withholding from the DASR Market by providing high offers. Conversely, 48 percent of units had offers of $0.00, either by choice or by default.

The fact that there is substantial structural market power in the DASR Market, together with the fact that the clearing prices in the DASR Market reflected a competitive result, suggests that market participants have the ability to exercise market power in this market but have not yet done so in a way that has affected market clearing prices.

While the MMU was represented at PJM stakeholder meetings during which the DASR Market was discussed, PJM did not request the assessment of the MMU as to whether the market would be expected to be structurally competitive or whether market power mitigation rules should be built into the market design. PJM has not implemented any form of market power mitigation in this market.

The MMU concludes that the DASR Market is not structurally competitive, based on the results in 2008. The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test. The MMU also concludes that the DASR Market results were competitive in 2008.

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 their revenue requirements (see Table 6-11 below). PJM defines a minimum critical black start for each transmission zone.[37]

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.[38]

Individual transmission owners, with PJM, identify the black start units included in each transmission owner's restoration plan. PJM defines required black start capability zonally and 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 their revenue requirements (see Table 6-11). PJM defines a minimum critical black start for each transmission zone.[39]

37 PJM Manual 36, System Restoration, Rev 9, June 30, 2008, pgs. 51-52.
38 PJM Tariff, Second Revised Sheet No. 33.01, March 1, 2007.
39 PJM Manual 36, System Restoration, Rev 9, June 30, 2008, pgs. 51-52.

Table 6-11 Black Start yearly zonal charges for network transmission use

Zone	Network Charges
AECO	$413,077
AEP	$722,265
AP	$120,933
BGE	$473,503
ComEd	$7,771,183
DAY	$143,645
DLCO	$26,209
DPL	$362,409
JCPL	$428,936
Met-Ed	$398,811
PECO	$695,457
PENELEC	$325,395
Pepco	$211,985
PPL	$131,513
PSEG	$921,219

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 Schedule 6A primarily was to provide a level of compensation sufficient to encourage the owners of identified critical resources to continue providing the service.[40] These provisions established a rolling two-year commitment, appropriate for older units whose remaining useful life was uncertain.

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 provider. 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

40 See PJM filing initiating FERC Docket No. ER02-2651-000 at 4 (September 30, 2002)("2002 Schedule 6A Filing").

into PJM.[41] 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, within which recovery was accelerated to the first two years.[42]

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's Critical Infrastructure Protection Standards (CIPS) 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 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 the FERC on February 19, 2009, and are now pending before the Commission.[43]

The current Schedule 6A calls for periodic review of the incentive factor, set at percent, which is applied to black start service related costs in a manner akin to a rate of return on equity. Under the pending proposal, all elements of the formula would be subject to biennial review.

Structure

There is no organized market for black start service in PJM. 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 the 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 vital for the industry collectively to obtain and the need to secure voluntary participation in the system restoration plans from 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. The significantly increasing

41 *See* Big Sandy Peaker Plant, LLC filing initiating FERC Docket No. ER06-1357 (August 11, 2006), and the Letter Order of acceptance (September 13, 2006); University Park Energy, LLC filing initiating FERC Docket No. ER04-212 (November 21, 2003), and Letter Order of acceptance (January 29, 2004).

42 *See* Lincoln Generating Facility, LLC filing initiating FERC Docket No. ER08-63-000 (October 16, 2007), and Letter Order of acceptance (December 12, 2007).

43 PJM filed the revised Schedule 6A in FERC Docket No. ER09-730-000.

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

PJM generally has managed the request-for-proposals process in an orderly and transparent manner. PJM has been vigilant in ensuring timely and adequate provision of service in system restoration plans. The MMU is concerned that the process does not ensure adequate scrutiny of the proposals.

Performance

There is no liquidity in the provision of black start service at locations identified in system restoration plans. Although the procurement process is transparent and administered well, it is not appropriate to characterize it as 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 substantial local market power. PJM has correctly described Schedule 6A and its formula rates as a cost-of-service recovery mechanism,[44] and its performance should be evaluated in that context.

PJM's filing in FERC Docket No. ER09-730 will allow the formula under Schedule 6A to recover new investment and reasonably conform the terms of commitment between service providers and their customers. However, the MMU is concerned about the level of increases that may result from CIPS costs applicable to 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 principle 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. The MMU recommends that PJM and the FERC, as well state regulators, reevaluate how black start service is procured.

44 *See* 2002 Schedule 6A Filing at 4.