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 services; 3) regulation and frequency response services; 4) energy imbalance service; 5) operating reserve -- synchronized reserve services; and 6) operating reserve -- supplemental reserve services.[1] Of these, PJM currently provides regulation, energy imbalance and synchronized reserve services through market-based mechanisms.[2] 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 generators up and down via an automatic control signal.[3] Regulation is provided, independent of economic signal, by generators with a short-term response capability (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 demand-side response (DSR). The term, "synchronized reserve market" refers only to the 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 it cannot be selected for both. The Regulation and Synchronized Reserve Markets are cleared simultaneously and cooptimized 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, inter-area transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

PJM does not provide a market for reactive power, but does ensure its adequacy through member requirements and scheduling.[4] 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.

Analysis of 2006 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM integrated five new control zones. When making comparisons to 2004 and 2005, the *2006 State of the Market Report* refers to three phases in calendar year 2004 and two phases in 2005 that correspond to those integrations.[5]

1 75 FERC ¶ 61,080 (1996).

2 The term "spinning reserve" has been replaced with "synchronized reserve," consistent with modifications made to PJM manuals. This change reflects the fact that demand-side resources may now provide synchronized reserve and such resources are not literally spinning reserve in every case, as are generators.

3 Regulation is used to help control the area control error (ACE). See *2006 State of the Market Report*, Volume II, Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE.

4 See PJM "Manual 11: Scheduling Operations," Revision 29 (August 11, 2006), p. 76.

5 For additional information on PJM's footprint and the definition of these phases, see *2006 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

On August 1, 2005, PJM integrated what had been five regulation control zones into one combined Regulation Market for a trial period. After the trial period and after a report by the PJM Market Monitoring Unit (MMU), PJM stakeholders will vote on whether to keep the combined market. The MMU provided that report on October 18, 2006, and it is under review by PJM members.[6]

PJM operates four Synchronized Reserve Markets: one for the Mid-Atlantic Region, one for the Western Region, one for the Southern Region (Dominion) and one for the ComEd Control Zone.

Overview

Regulation Market

Market Structure

- **Supply.** The supply of offered and eligible regulation in PJM was generally both stable and adequate. Potential regulation supply was enhanced during 2006 by allowing demand-side resources to offer regulation and to satisfy up to 25 percent of the regulation requirement, although no demand-side resources offered regulation during 2006. The ratio of eligible regulation offered to regulation required averaged 2.60 throughout 2006.

- **Demand**. The regulation requirement is set daily for the entire day by PJM to be 1.0 percent of the forecast-peak load for PJM. This requirement was established in August 2006.

- **Market Concentration.** During 2006, the PJM Regulation Market had an average Herfindahl-Hirschman Index (HHI) of 1256 which is classified as "moderately concentrated."[7] The largest hourly market share was 40 percent, and 43 percent of all hours had a maximum market share greater than 20 percent. There were no suppliers with annual average market shares greater than, or equal to, 20 percent. Approximately 26 percent of hours had three pivotal suppliers. The MMU concludes from these results that the PJM Combined Regulation Market in 2006 was characterized by structural market power in 26 percent of the hours.

Market Conduct

- **Offers.** The offer price is provided by the unit owner, is applicable for the entire operating day and, with lost opportunity cost (LOC), comprises the total offer to the Regulation Market. The regulation offer price is subject to a $100 per MWh offer cap, with the exception of the dominant suppliers, whose offers are capped at marginal cost plus $7.50 per MWh plus lost opportunity cost. All suppliers are paid the market-clearing price. Based on MMU estimates of the marginal cost of regulation, 33 percent of offers exceeded competitive levels in 2006.

6 See Market Monitoring Unit, "Analysis of the Combined Regulation Market: August 1, 2005 through July 31, 2006" (October 18, 2006) <http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/20061018-mmu-regulation-market-report.pdf> (76.1 KB).

7 See *2006 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 Performance

- **Price.** For the PJM Regulation Market during 2006 the average price per MWh (regulation market-clearing price including lost opportunity cost) associated with meeting PJM's demand for regulation was $32.69. This represents a decrease of $19.17 from the average price for regulation during 2005. In 2006, 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 30 percent of all hours.

Synchronized Reserve Market

The structure of each Synchronized Reserve Market (the term, "synchronized reserve market" refers only to Tier 2 synchronized reserve) has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. As a result, these markets are operated as markets 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 PJM Mid-Atlantic Region, the ComEd Control Zone, the Western Region and Southern Region 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.

Market Structure

- **Supply.** For the PJM Mid-Atlantic Synchronized Reserve Region, the offered and eligible excess supply ratio was 1.64. For the ComEd Synchronized Reserve Control Zone, the ratio was 1.46.[8] These excess supply ratios are 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. In August 2006 DSR resources began participating in PJM Synchronized Reserve Markets. As of the end of 2006, the MW contribution of DSR resources to the supply of synchronized reserve remained small, but increasing. Market rules limit the contribution of DSR resources to 25 percent of the administratively required synchronized reserve.

- **Demand.** The average synchronized reserve requirement was: 1,109 MW for the Mid-Atlantic Synchronized Reserve Region; 222 MW for the ComEd Synchronized Reserve Control Zone; 423 MW for the Western Synchronized Reserve Region; and 9 MW for the Southern Synchronized Reserve Region. These requirements are a function of administratively determined, regional requirements. Market demand is less than the requirement by the amount of Tier 1 synchronized reserve available at the time a Synchronized Reserve Market is cleared. The average demand for synchronized reserve was: 293 MW for the Mid-Atlantic Synchronized Reserve Region; 59 MW for the ComEd Synchronized Reserve Control Zone; 0 MW for the Southern Synchronized Reserve Region; and 3 MW for the Western Synchronized Reserve Region.

8 The Synchronized Reserve Markets in the Western Region and Southern Region cleared in so few hours that related data for those markets are not meaningful.

- **Market Concentration**. In 2006, market concentration was high in the Tier 2 Synchronized Reserve Markets. The average cleared synchronized reserve market HHI for the Mid-Atlantic Synchronized Reserve Region throughout 2006 was 5686. The average HHI for the ComEd Synchronized Reserve Control Zone was 8305. The average HHI for the Western Synchronized Reserve Region was 7944. The HHI for the Southern Synchronized Reserve Region was always 10000.

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 total offer 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 MWh, 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 was $14.94 per MW in 2006, a $0.53 per MW increase from 2005. The load-weighted, average price in 2006 for Tier 2 synchronized reserve was $14.57 per MW in the Mid-Atlantic Synchronized Reserve Region, $16.69 in the ComEd Synchronized Reserve Control Zone, $9.14 in the Western Synchronized Reserve Region and $23.49 in the Southern Synchronized Reserve Region.

Conclusion

PJM consolidated its Regulation Markets into a single Combined Regulation Market, on a trial basis, effective August 1, 2005. The MMU concludes from the analysis of the 2006 data that the PJM Regulation Market in 2006 was characterized by structural market power in 26 percent of the hours.[9] This conclusion is based on the results of the three pivotal supplier test. The MMU also concludes that PJM's consolidation of its Regulation Markets resulted in improved performance and in increased competition compared to the PJM Mid-Atlantic Regulation Market or the Western Region Regulation Market on a stand-alone basis.[10] The MMU also concludes that the performance of the Regulation Market was more competitive in calendar year 2006 than during the first 12 months of the Regulation Market, August 1, 2005, through July 31, 2006. These conclusions are based on improved HHI results and fewer hours during which there were three pivotal suppliers. The combined market results include the effects of the current mitigation mechanism which offer caps the two dominant suppliers in every hour. The MMU concludes that it would be preferable to retain the existing, experimental single PJM Regulation Market as the long-term market if appropriate mitigation can be implemented that addresses only the hours in which structural market power exists and which therefore provides an incentive for the continued development of competition.

With respect to mitigation, the MMU recommends 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

9 This is the same conclusion reached in the MMU report on the first year of the Combined Regulation Market. See Market Monitoring Unit, "Analysis of the Combined Regulation Market: August 1, 2005 through July 31, 2006" (October 18, 2006) <http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/20061018-mmu-regulation-market-report.pdf> (76.1 KB).

10 *2005 State of the Market Report* (March 8, 2006), pp. 260-263.

market structure is noncompetitive, and that market power mitigation be applied only to the companies failing the market structure tests. More specifically, the MMU recommends that the three pivotal supplier test be applied hourly in the Regulation Market using a market definition of all eligible offers less than or equal to 1.50 times the clearing price and that mitigation be applied to only those regulation-owning companies that fail the test in that hour.[11]

This more flexible and real-time approach to mitigation represents an improvement over the current approach to mitigation which requires cost-based offers from the dominant companies at all times. The proposed 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 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 conclusions related to the structure of the Regulation Market are consistent with the conclusions reached in the *2005 State of the Market Report*, which stated: "The structure of the Mid-Atlantic Region and Western Region Regulation Markets was evaluated and the MMU concluded that these markets are not structurally competitive as they are characterized by a combination of one or more structural elements including high levels of supplier concentration, high individual company market shares, significant hours with pivotal suppliers and inelastic demand." The 2005 report also stated, "The Regulation Markets produced competitive results throughout calendar year 2005 based on the regulation market-clearing price."[12] The MMU cannot conclude that the Regulation Market in 2006 produced competitive results or noncompetitive results, based on our analysis of the relationship between the offer prices and marginal costs of units providing regulation. That is one of the reasons that the MMU recommends that all suppliers be required to provide cost-based regulation offers as part of real-time market power mitigation.

PJM's Synchronized Reserve Markets have worked effectively with offers based on marginal costs plus a margin and with all participants paid a market-clearing price based on the marginal offer including opportunity costs, despite the fact that these markets are characterized by high levels of seller concentration and inelastic demand.

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 costs. 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.

11 See *2006 State of the Market Report*, Volume II, Appendix J, "Three Pivotal Supplier Test."

12 *2005 State of the Market Report* (March 8, 2006), pp. 250-251.

Overall, the MMU concludes that the Regulation Market's results cannot be determined to have been competitive or to have been noncompetitive. The MMU concludes that the Synchronized Reserve Markets' results were competitive.

Regulation Market

Market Structure

The PJM Regulation Market continued to mature in 2006. DSR participation was introduced in 2006, but no demand-side resources made offers in the Regulation Market in 2006.

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 both offered and eligible.

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 actually 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 is a combustion turbine that meets specific operating parameter requirements.

Only those offers which are 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 2006 was 2.60. Even during periods of diminished supply such as off-peak hours, eligible regulation supply was more than 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 *2006 State of the Market Report* as "required regulation."

The PJM regulation requirement was set by Reliability*First* Corporation in August 2006 to be 1.0 percent of the forecast-peak load for the entire day.[13] Prior to August, for the PJM Mid-Atlantic Region the regulation requirement for peak periods had been 1.1 percent of the peak-load forecast and for off-peak periods it had been 1.1 percent of the valley-load forecast.[14] During 2006 the PJM regulation requirements ranged from 692 MW to 1,434 MW. The average required regulation was 929 MW.

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 presented here differs in two ways from the FERC's delivered price test. The delivered price test would start with the universe of regulation offered and eligible and then limit the analysis to the relevant competitive offers, defined as those offered and eligible units that could provide regulation at less than or equal to 1.05 times the clearing price. The analysis here also includes separately 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 results of the one and three pivotal supplier tests. 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 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.

13 See Reliability*First* Corporation < http://www.reliabilityfirst.org/> (1 KB).

14 See PJM "Manual 11: Scheduling Operations," Revision 25 (August 19, 2005), p. 51.

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.

The analysis presented here goes further in order to analyze the significance of excess supply. The MMU applies the pivotal supplier test using one and three pivotal suppliers. In addition, when there are hours with one or 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 can reasonably be deemed competitive.

PJM Regulation Market – 2006

During 2006 the PJM Regulation Market offer capability was 6,368 MW.[17] Total offer 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 both offered and eligible to participate on an hourly level in the market were lower than the total regulation capability. In 2006 the average daily offer level was 3,926 MW or 62 percent of offer capability while the average hourly eligible offer level was 2,412 MW or 38 percent of offer capability. Although regulation is offered daily, eligible regulation changes hourly. Typically less regulation is eligible to be assigned during off-peak hours because fewer steam units are running during those hours. Table 6-1 shows capability, daily offer and average hourly eligible MW for all hours as well as for off-peak and on-peak hours.

Table 6-1 PJM regulation capability, daily offer and hourly eligible: Calendar year 2006

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	6,368	3,926	62%	2,412	38%
Off Peak	6,368	NA	NA	2,237	35%
On Peak	6,368	NA	NA	2,603	41%

The ratio of the hourly regulation supply offered and eligible to the hourly regulation requirement averaged 2.60 for PJM during 2006. 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.

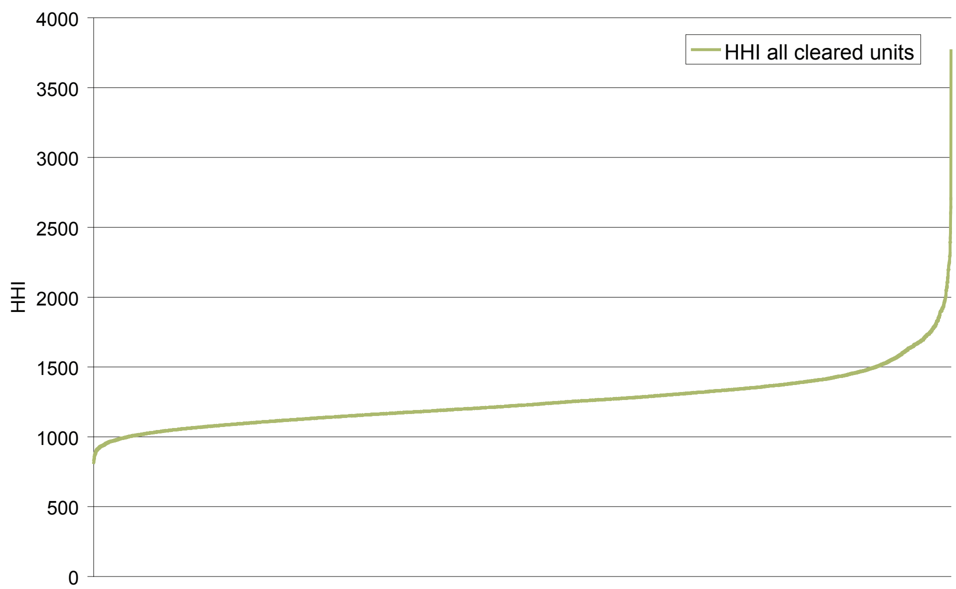
Hourly HHI values were calculated based upon cleared regulation. HHI values ranged from a maximum of 3763 to a minimum HHI of 816, with an average value of 1256, moderately concentrated under the FERC's definitions. Table 6-2 summarizes the 2006 PJM regulation market HHIs.

Table 6-2 PJM cleared regulation HHI: Calendar year 2006

Market Type	Minimum	Average	Maximum
All Units	816	1256	3763

The PJM Regulation Market exhibited consistent moderate market concentration with about 4 percent of the periods with an HHI less than 1000 and about 2 percent of the periods with an HHI greater than 1800. See the HHI duration curve in Figure 6-1.

Figure 6-1 PJM Regulation Market's HHI duration curve: Calendar year 2006



Market shares for cleared regulation for all of 2006 are listed in Table 6-3. The highest annual average hourly market share was 12 percent and the second and third highest annual average hourly market shares were both 11 percent. The largest hourly market share was 40 percent, and 43 percent of all hours had a maximum market share greater than 20 percent.

Table 6-3 Top three cleared regulation market shares: Calendar year 2006

Company Market Share Rank	Cleared Regulation Top Market Shares
1	12%
2	11%
3	11%

When all eligible regulating units whose price is less than, or equal to, the regulation market-clearing price (RMCP) times 1.05 are included in the definition of the relevant market, 7 percent of hours failed the one pivotal supplier test during 2006. (See Table 6-4.) This means that for 7 percent of hours the total regulation requirement could not be met in the absence of the largest supplier. One supplier of regulation was pivotal in 78 percent of the hours with one pivotal supplier and a second company was pivotal in 42 percent of the hours with one pivotal supplier. Seventy-nine percent of hours failed the three pivotal supplier test. One supplier of regulation was pivotal in 96 percent of the three pivotal supplier hours, a second company was pivotal in 67 percent and a third company was pivotal in 65 percent of three pivotal supplier hours.

Table 6-4 Regulation market pivotal suppliers: Calendar year 2006

Market Definition	Hours with One Pivotal Supplier (Percent)	Hours with Three Pivotal Suppliers (Percent)
Price ≤ RMCP * 1.05	7%	79%
Price ≤ RMCP * 1.5	0%	26%

When all eligible regulating units whose price is less than, or equal to, the market-clearing price times 1.5 are included in the definition of the relevant market, less than one percent of hours failed the one pivotal supplier test during 2006.[18] (See Table 6-4.) Twenty-six percent of hours failed the three pivotal supplier test. One company was pivotal in 98 percent of those hours, a second company was pivotal in 79 percent and a third company was pivotal in 72 percent of three pivotal supplier hours. Thus, in addition to failing the relevant pivotal supplier tests 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 was persistent and repeated during 2006. The MMU concludes from these results that the PJM Regulation Market in 2006 was characterized by structural market power. This conclusion is based on the pivotal supplier results, and in particular, on the results of the three pivotal supplier test with a market definition that includes all offers with a price less than or equal to 1.50 times the market-clearing price.

18 The number of hours which failed the three pivotal supplier test is rounded to zero.

Market Conduct

Offers

Generators wishing to participate in the PJM Regulation Market must submit regulation offers for specific units by 1800 EPT of the day before the operating day. The regulation offer price is subject to a $100 per MWh offer cap with the exception of the dominant suppliers, whose offers are capped at marginal cost plus $7.50 per MWh. As in any competitive market, regulation offers at marginal cost are considered to be competitive. In PJM, a $7.50 per MWh adder is considered to be consistent with competitive offers based on an analysis of historical offer behavior.

The offer price is the only component 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 (available, unavailable or self-scheduled); regulation capability; and high and low regulation limits. 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 upon 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.[19] The total offer price is the sum of the unit-specific offer and the opportunity cost. In order to clear the market, PJM ranks all offered and eligible regulating resources in ascending total offer price order, 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. The regulation market price that results is the RMCP, and the unit that sets this price is the marginal unit.

In 2006, offers from some regulation suppliers exceeded the competitive level. 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 MW. The cost of providing regulation has not been provided by suppliers. While the MMU recommended that the provision of such data be required and the PJM systems were created to allow the provision of cost data, provision of the data is not mandatory and suppliers do not currently provide the data. The MMU estimated hourly marginal costs for units that provided regulation during 2006.[20] Based on those estimates, 33 percent of unit daily offers exceeded marginal costs.

19 PJM estimates the opportunity cost for units providing regulation based on a forecast of locational marginal price (LMP) for the upcoming hour. Opportunity cost is included in the market-clearing price.

20 See PJM "Manual 15: Cost Development Guidelines," Revision 7 (August 3, 2006).

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.[21]

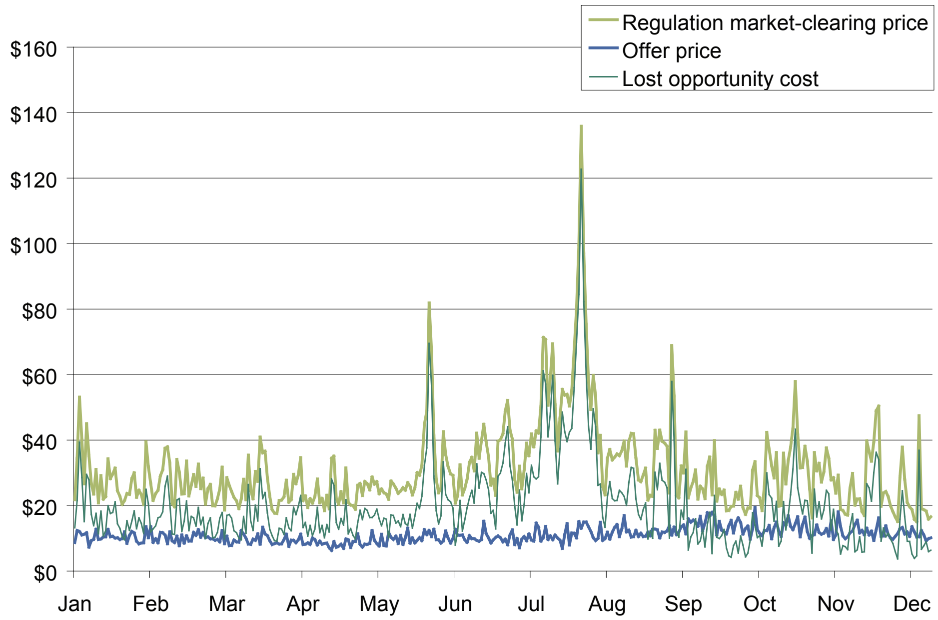
In 2006, offers at levels greater than the competitive level set the clearing price for regulation in 30 percent of hours. Of the 30 percent, 8 percent were between $0 and $7.50 per MW above the competitive level; 16 percent were between $7.50 and $10 per MW above the competitive level, and 6 percent were greater than $10 per MW 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 2006 was $11.36, so an additional $7.50 per MW is a markup of about 66 percent. These results mean that the MMU cannot conclude that the Regulation Market results were competitive in 2006 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 recommends that market participants be required to submit the cost of regulation, consistent with the definitions in PJM's "Cost Development Guidelines" when daily regulation offers are submitted in order both to permit analysis and to permit the recommended defined, targeted mitigation.[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 offered regulation into the market and were 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 unit incurred. Although most units are paid RMCP times their assigned regulation MW, a substantial portion of the RMCP is the lost opportunity cost, based upon 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 lost opportunity cost. As shown in Figure 6-2 more than half of the regulation price is the lost opportunity cost 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 2006 was $11.36 per MW. The load-weighted, average LOC of the marginal unit for the PJM Regulation Market during 2006 was $23.06. In the PJM Regulation Market the marginal unit LOC averaged 70 percent of the RMCP.

21 See PJM "Manual 28: Operating Agreement, Accounting," Revision 27, Section 4, "Regulation Credits" (October 1, 2004), pp. 26-27. PJM uses estimated opportunity cost to clear the market and real-time opportunity cost to compensate generators that provide regulation and spinning. Real-time opportunity cost is calculated using real-time LMP.

22 See PJM "Manual 15: Cost Development Guidelines," Revision 7 (August 3, 2006).

Figure 6-2 PJM Regulation Market's daily average market-clearing price, lost opportunity cost and offer price: Calendar year 2006

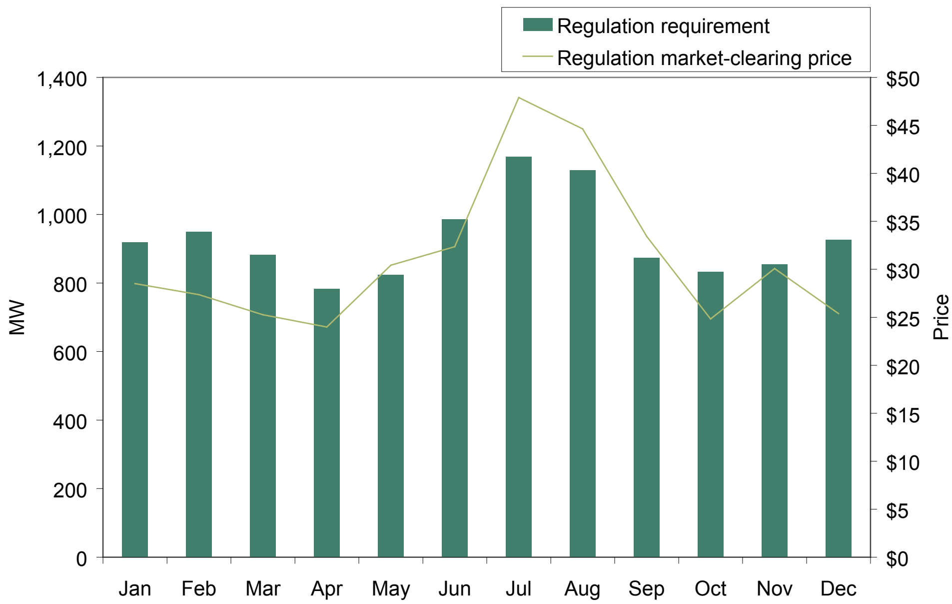


On a shorter-term basis, regulation prices follow a daily and weekly pattern. The supply of regulation is most plentiful between 0600 and 2300 EPT, Monday to Friday.

During weekends and 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.

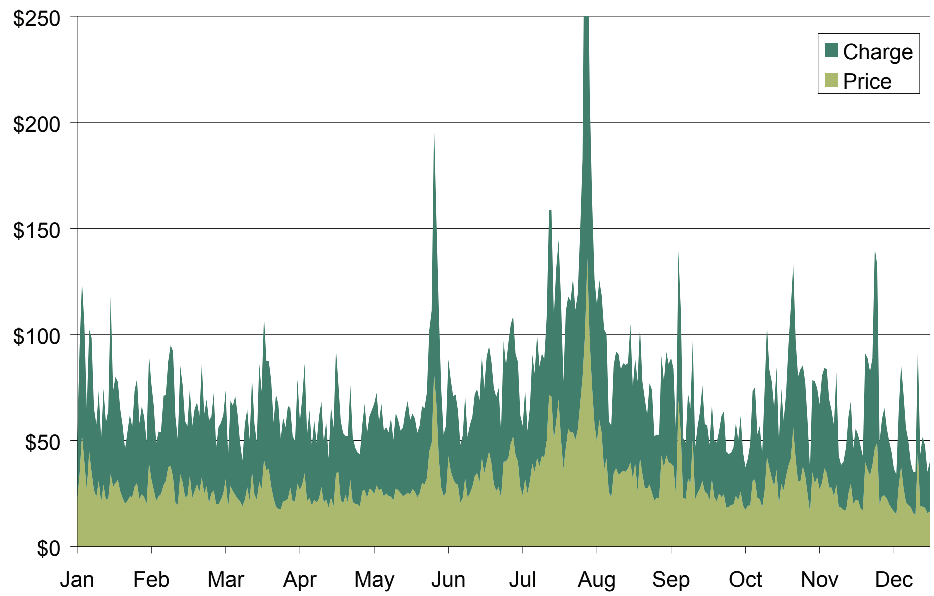
Figure 6-3 shows the level of demand for regulation by month in 2006 and the corresponding level of regulation price.

Figure 6-3 Monthly average regulation demand (required) vs. price: Calendar year 2006



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 units that must be redispatched 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 charge per MWh is higher than the RMCP. Figure 6-4 compares the regulation charge per MWh with the regulation-clearing price to show the difference between the price of regulation and the total charge for regulation.

Figure 6-4 Daily average regulation charge and price: Calendar year 2006



For all of 2006, the average regulation price was $32.69. The average regulation charge was $44.98. The difference between the regulation market price and the actual charge for regulation was significant in 2006. The charge for regulation was 37.6 percent higher than the market price of regulation. While the reasons are not yet fully understood, the payment of a larger portion of regulation charges on a unit-specific basis rather than on the basis of a market-clearing price is a cause for concern as it results in a weakened market price signal to the providers of regulation.

Synchronized Reserve Market

Market Structure

The PJM Synchronized Reserve Market includes the Mid-Atlantic Region's Synchronized Reserve Market, the Western Region's Synchronized Reserve Market, the ComEd Control Zone's Synchronized Reserve Market and the Southern Region's Synchronized Reserve Market.

Supply

Synchronized reserve is an ancillary service defined as generation or curtailable load that is synchronized to the system and capable of producing output 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. As of August 2006, 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 can be provided by reductions in load.

All of the units that participate in the Synchronized Reserve Markets are categorized as Tier 2 synchronized reserve. Tier 1 resources are those units that are online, following economic dispatch and able to respond to a spinning event by ramping up from their present output. All units 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 the synchronized reserve market rules, Tier 1 resources are paid when they respond to an identified spinning event as an incentive to respond when needed.[23] 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 the 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 reserve resources. 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. 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 unit, based on the simultaneous clearing of the Regulation Market and the Synchronized Reserve Market.[24]

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.[25, 26] The market-clearing price is comprised of the marginal unit's synchronized reserve offer price, the cost of energy use, the start-up 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 Synchronized Reserve Markets for the Mid-Atlantic Region, the Western Region, the ComEd Control Zone and the Southern Region all operate under similar business rules. The Tier 2 Synchronized Reserve Market in each of PJM's synchronized reserve areas is cleared on cost-based offers because the structural

23 See PJM "Manual 11: Scheduling Operations," Revision 29 (August 11, 2006), p. 60.

24 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.

25 See PJM "Manual 11: Scheduling Operations," Revision 29 (August 11, 2006), p. 61.

26 See PJM "Manual 15: Cost Development Guidelines," Revision 7 (August 3, 2006), p. 37.

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 PJM Mid-Atlantic Region, the offered and eligible excess supply ratio was 1.64. For the ComEd Control Zone, the ratio was 1.46.[27] These excess supply ratios are determined using the administratively determined requirement for 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.

Demand

The demand for Tier 2 synchronized reserve is determined by subtracting the amount of forecast Tier 1 synchronized reserve available from each synchronized reserve control area's synchronized reserve requirement for the period. The total synchronized reserve requirement is different for each of the four, regional Synchronized Reserve Markets.[28] For the PJM Mid-Atlantic Synchronized Reserve Market, the requirement is 75 percent of the largest contingency in the region, provided that double the remaining 25 percent of the largest contingency is available as nonsynchronized, 10-minute reserve. For the ComEd Synchronized Reserve Market, the requirement is 50 percent of the ComEd Control Zone's load ratio share of the largest contingency in the North American Electric Reliability Council's (NERC) Mid-America Interconnected Network, Inc. (MAIN) Region. For the PJM Western Synchronized Reserve Region, the requirement is 1.5 percent of the daily peak-load forecast. For the PJM Southern Synchronized Reserve Region, the requirement is the Dominion Control Zone's load ratio share of the largest system contingency within the Virginia and Carolinas Area (VACAR), minus the available 15-minute quick start capability within the PJM Southern Synchronized Reserve Region.

Computed in accordance with the requirements above, the 2006 average MW synchronized reserve requirement was: 1,109 MW for the PJM Mid-Atlantic Region; 222 MW for the ComEd Control Zone; 423 MW for the Western Region; and 9 MW for the Southern Region.

27 The Synchronized Reserve Markets in the Western Region and Southern Region cleared in so few hours that related data for those markets are not meaningful.
28 See PJM "Manual 11: Scheduling Operations," Revision 29 (August 11, 2006), p. 63.

Figure 6-5 and Figure 6-6 show the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW purchased during 2006 for the PJM Mid-Atlantic and the ComEd Synchronized Reserve Markets. Results for the Western Synchronized Reserve Region and the Southern Synchronized Reserve Region are not shown because Tier 2 synchronized reserve MW purchases were insignificant in those areas during 2006.

Figure 6-5 PJM's Mid-Atlantic Tier 2 Synchronized Reserve Region's monthly required vs. purchased: Calendar year 2006

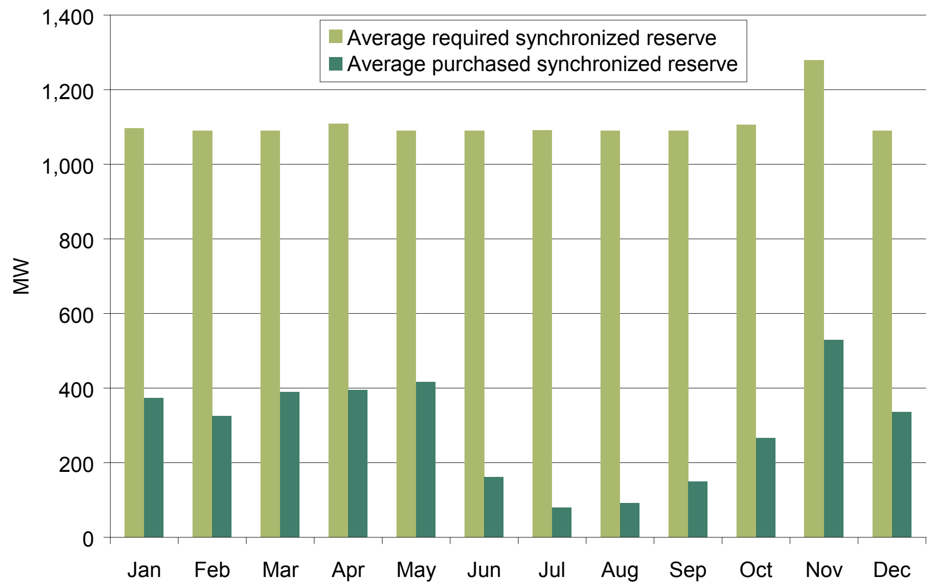
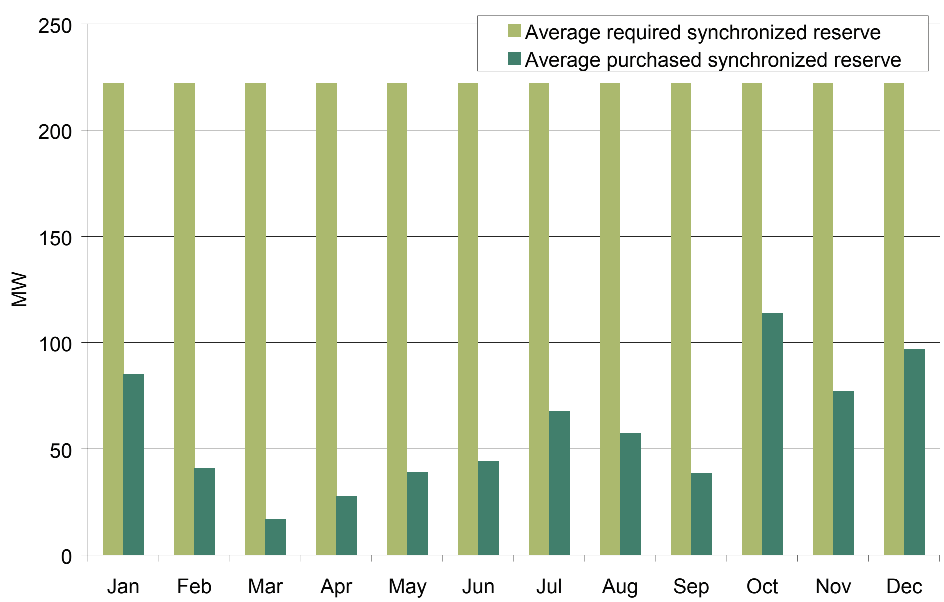


Figure 6-6 PJM's ComEd Tier 2 Synchronized Reserve Zone's monthly required vs. purchased: Calendar year 2006



The difference between the required amount of synchronized reserve and the amount of Tier 2 synchronized reserve purchased is the amount of Tier 1 synchronized reserve available on the system. During the first quarter of 2006, PJM dispatchers noticed that actual Tier 1 MW generated in response to spinning events was higher than estimated Tier 1 MW. PJM analysis resulted in improved Tier 1 estimating procedures and higher Tier 1 estimates.[29] The changes to Tier 1 estimates were implemented in June and resulted in a drop in the amount of Tier 2 synchronized reserve MW purchased.[30] (See Figure 6-5.)

Synchronized reserve MW requirements are different for each of the four synchronized reserve areas in PJM. These differences are the result of specifications from regional reliability councils, reserve-sharing arrangements with neighboring control areas and the types of generation available in the control area.

The Southern Synchronized Reserve Region is a member of the VACAR subregion of NERC's Southeastern Electric Reliability Council (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. The amount of 15-minute quick start reserve available in VACAR is sufficient to make Tier 2 synchronized reserve demand zero for most hours.

Similarly, in the Western Synchronized Reserve Region most of the required synchronized reserve is available as Tier 1 from large, frequently running baseload units, reducing its Tier 2 synchronized reserve demand to zero in most hours.

For the PJM Mid-Atlantic Synchronized Reserve Region, the synchronized reserve requirement is defined as that amount of 10-minute reserve that must be synchronized to the grid. Mid-Atlantic Area Council (MAAC) standards currently set that amount at 75 percent of the largest contingency in that Synchronized Reserve Zone provided that double the remaining 25 percent is available as non-synchronized 10-minute reserve.[31] The ComEd Synchronized Reserve Control Zone requirement is defined as 50 percent of ComEd's load ratio share of the largest system contingency within MAIN. For the PJM Mid-Atlantic Region the hourly synchronized reserve requirement was usually 863 MW (19.5 percent of total hours) during off-peak hours and 1,150 MW (73.7 percent of total hours) during on-peak hours. Sometimes temporary grid conditions such as maintenance outages can cause double contingencies so there were times throughout the year when the on-peak synchronized reserve requirement was 1,360 MW (5.8 percent of total hours). The average hourly synchronized reserve required for the PJM Mid-Atlantic Region was 1,109 MW. In the ComEd Control Zone, the hourly requirement was always 222 MW.

29 See Stanley Williams, manager, PJM Performance Compliance, "Spinning Market Generator Performance," PJM Market Implementation Committee Meeting (August 8, 2006). The analysis showed that the actual Tier 1 response during spinning events was 171 percent of PJM's estimate of Tier 1 response.

30 See PJM "Manual 12: Dispatching Operations," Revision 13 (May 26, 2006), p. 68.

31 See PJM "Manual 11: Scheduling Operations," Revision 29 (August 11, 2006), p. 63.

Market Concentration

There are several metrics used to measure market concentration. All of them indicate a concentrated market. Market share data show that the Synchronized Reserve Market in both the PJM Mid-Atlantic Region and the ComEd Control Zone is dominated by a relatively small number of companies. (See Table 6-5 and Table 6-6.)

Table 6-5 The PJM Mid-Atlantic Region's Tier 2 cleared synchronized reserve market shares: Calendar year 2006

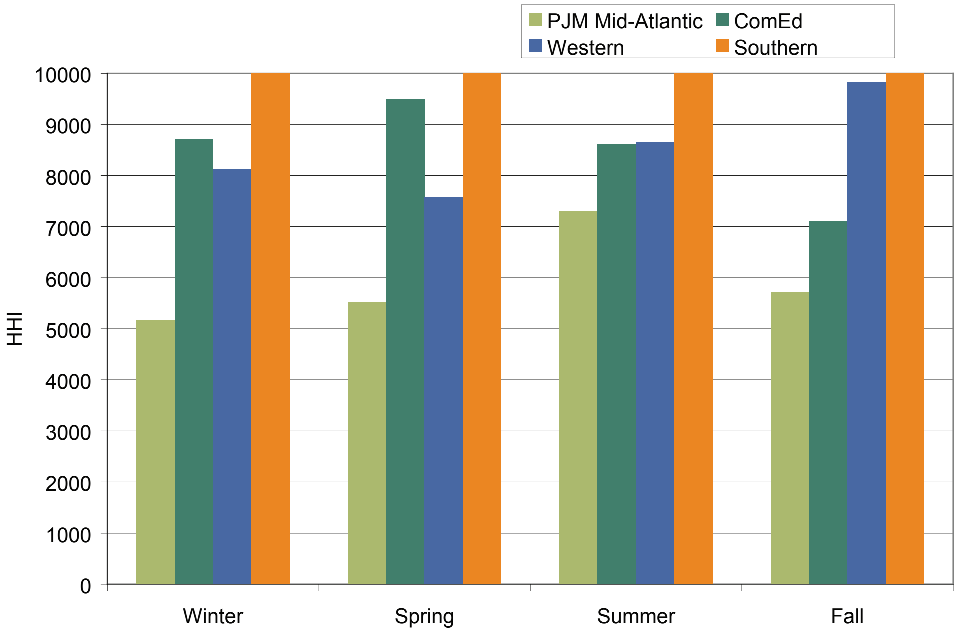
Company Market Share Rank	Cleared Synchronized Reserve: All Units
1	43%
2	19%
3	18%
4	10%
5	2%

Table 6-6 The PJM ComEd Control Zone's Tier 2 cleared synchronized reserve market shares: Calendar year 2006

Company Market Share Rank	Cleared Synchronized Reserve: All Units
1	59%
2	16%
3	15%

The cleared Tier 2 Synchronized Reserve Markets for all four geographic areas are highly concentrated. (See Figure 6-7 which also provides seasonal details.) During calendar year 2006, in the PJM Mid-Atlantic Region average HHI for cleared Tier 2 synchronized reserve was 5686. In the ComEd Control Zone during 2006 the average HHI for cleared Tier 2 synchronized reserve was 8305. In the Western Region the average HHI for cleared Tier 2 synchronized reserve was 7944. In the Southern Region the HHI was 10000.

Figure 6-7 Cleared Tier 2 synchronized reserve market seasonal HHI: Calendar year 2006



The pivotal supplier metric provides an analytical approach to the issue of excess supply on the synchronized reserve market-clearing price (SRMCP).[32] (See Table 6-7.) While there are only a few major suppliers, the supply of eligible Tier 2 synchronized reserve is generally much larger than the hourly demand. When the relevant market is defined to include all offers at less than or equal to 1.05 times the clearing price, in the Mid-Atlantic Region there is a single pivotal supplier in 24 percent of the hours and three pivotal suppliers in 92 percent of the hours. When the relevant market is defined to include all offers at less than or equal to 1.50 times the clearing price, in the Mid-Atlantic Region there is a single pivotal supplier in 3 percent of the hours and three pivotal suppliers in 66 percent of the hours. The results are comparable for the ComEd Control Zone with more hours failing the single and three pivotal supplier tests. The pivotal supplier results indicate that the markets for synchronized reserve in the Mid-Atlantic Region and the ComEd Control Zone are not structurally competitive.

Table 6-7 The Mid-Atlantic Region's and the ComEd Control Zone's Tier 2 synchronized reserve market percent pivotal supplier hours: Calendar year 2006

Market Definition	One Pivotal Supplier (Percent Hours)	Three Pivotal Supplier (Percent Hours)
PJM Mid-Atlantic; Price ≤ SRMCP * 1.5	3%	66%
PJM Mid-Atlantic; Price ≤ SRMCP * 1.05	24%	92%
ComEd; Price ≤ SRMCP * 1.5	45%	100%
ComEd; Price ≤ SRMCP * 1.05	48%	100%

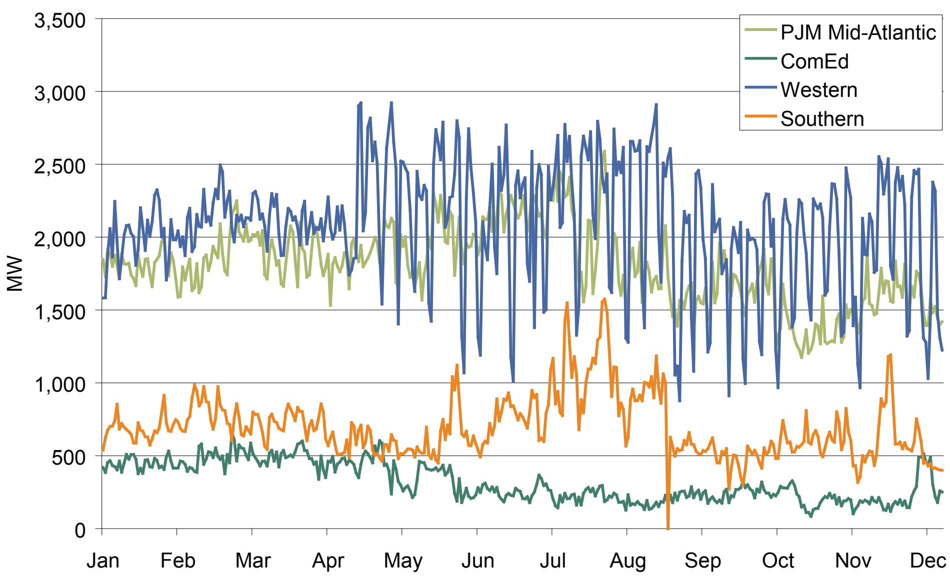
32 See *2006 State of the Market Report*, Volume II, Appendix J, "Three Pivotal Supplier Test."

Market Conduct

Offers

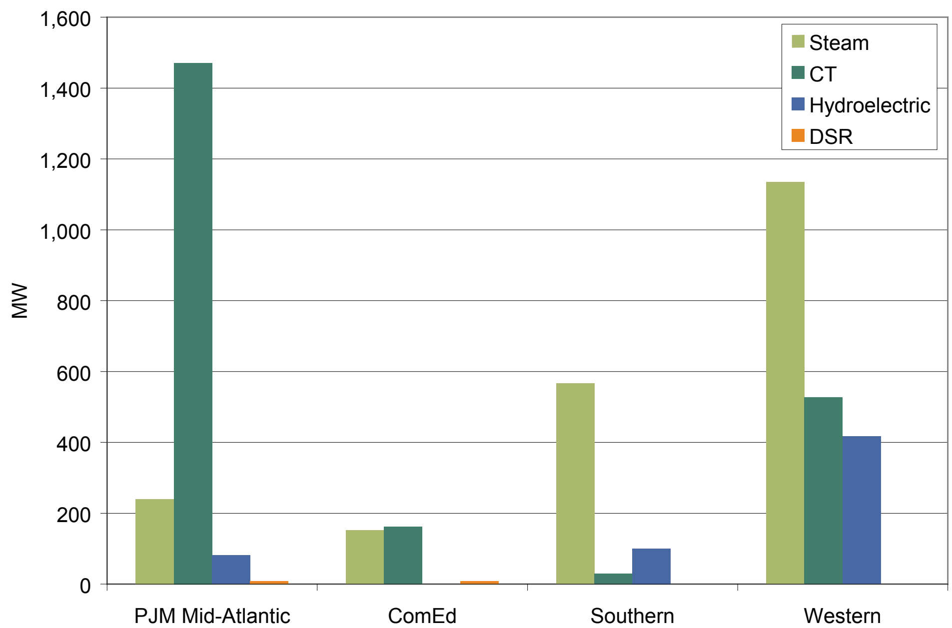
Figure 6-8 shows the daily average hourly eligible Tier 2 synchronized reserve offers. The level of eligible synchronized reserve displays considerable variability because it is calculated hourly and reflects current market and grid conditions, including LMP, unit dispatch and system constraints.

Figure 6-8 Tier 2 synchronized reserve average hourly eligible volume (MW): Calendar year 2006



Synchronized reserve is offered by steam, CT, hydroelectric and DSR resources. Figure 6-9 shows average eligible MW volume by ancillary service area and unit type.

Figure 6-9 Average daily Tier 2 synchronized reserve eligible by unit type (MW): Calendar year 2006



Market Performance

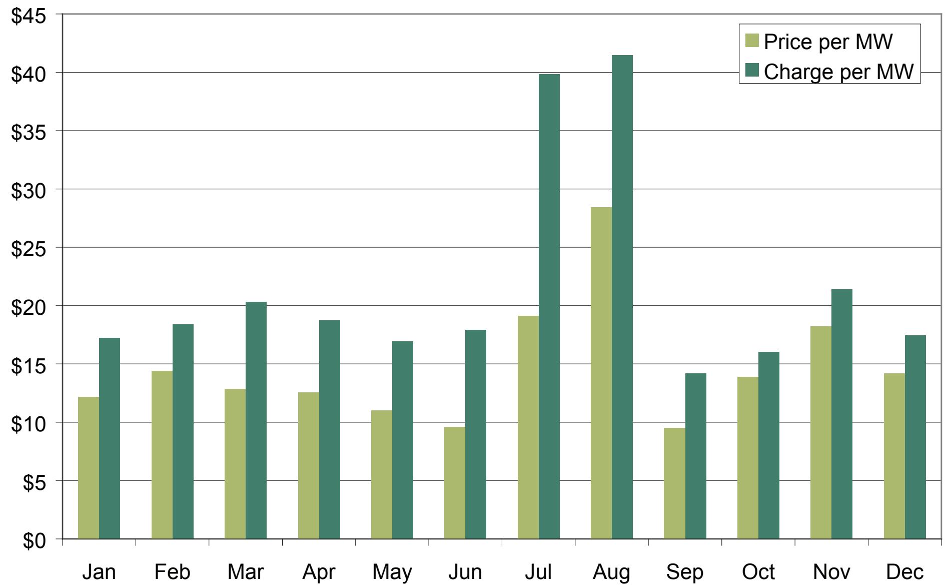
Price

Figure 6-10 shows the load-weighted, average Tier 2 SRMCP 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 non-economic 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 load-weighted, average price for synchronized reserve in the PJM Mid-Atlantic Region during 2006 was $14.57. The load-weighted, average price for synchronized reserve in the ComEd Control Zone was $16.69. Only 6 percent of hours in the Western Region cleared the Synchronized Reserve Market in 2006 with an average price of $9.14. Less than 1 percent of hours in the Southern Region cleared Synchronized Reserve Market in 2006 with an average price of $23.49.

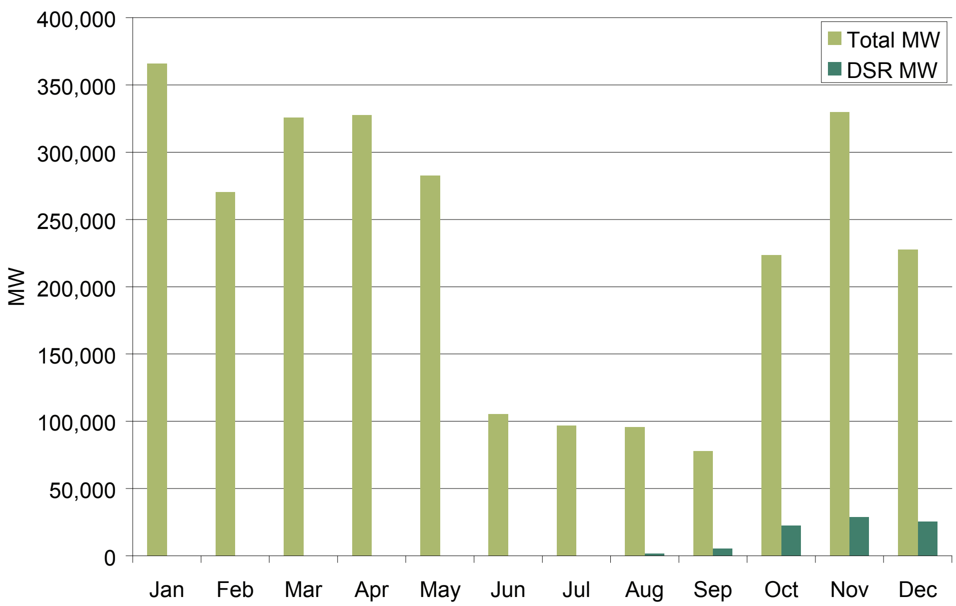
The difference between the Tier 2 synchronized reserve market price and the actual charge for Tier 2 synchronized reserve was significant in 2006. The load-weighted, average monthly price of Tier 2 synchronized reserve for the PJM Mid-Atlantic Region for 2006 was $14.57. The load-weighted, average monthly charge for Tier 2 synchronized reserve for PJM for 2006 was $21.65. The charge for Tier 2 synchronized reserve was 49 percent higher than the market price of Tier 2 synchronized reserve. While the reasons are not yet fully understood, the payment of a larger portion of synchronized reserve charges on a unit-specific basis rather than on the basis of a market-clearing price is a cause for concern as it results in a weakened market price signal to the providers of Tier 2 synchronized reserve.

Figure 6-10 Comparison of PJM Tier 2 synchronized reserve price and charge: Calendar year 2006



Demand-side resources began participating in the Synchronized Reserve Markets in August 2006. Figure 6-11 shows total monthly synchronized reserve cleared MW and cleared MW for DSR synchronized reserve. Figure 6-11 also shows a drop in the amount of synchronized reserve cleared starting in June. PJM changed reserve reporting procedures which resulted in higher estimated Tier 1 reserve which in turn reduced the amount of Tier 2 synchronized reserve needed to satisfy the synchronized reserve requirement.[33] Cleared Tier 2 synchronized reserve MW increased in November as the result of a bus outage resulting in a double contingency from November 7 through November 28. For every hour during this period the amount of synchronized reserve required was 1,360 MW as opposed to the usual 1,150 MW during on-peak and 863 MW during off-peak periods.

Figure 6-11 PJM Tier 2 synchronized reserve cleared MW: Calendar year 2006



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. None of PJM's Synchronized Reserve Markets had significant deficits during 2006.

33 See PJM "Manual 12: Dispatching Operations," Revision 13 (May 26, 2006), p. 29.