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 and synchronized 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 generators 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.

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.

The PJM Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance of the PJM Regulation Market and of its two Synchronized Reserve Markets for 2007, comparing market results to 2006 and to certain other prior years.[3]

1 75 FERC ¶ 61,080 (1996).

2 Regulation is used to help control the area control error (ACE). See *2007 State of the Market Report,* Volume II, Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE.

3 During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2007 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

Overview

Regulation Market

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 MMU, PJM stakeholders will vote on whether to keep the combined market. The MMU provided that report on October 18, 2006, and the issue is still under review by PJM members.[4] Both the *2006 State of the Market Report* and the *2007 State of the Market Report* have updated the analysis presented in that report.

Market Structure

- Supply. During 2007, 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 2007. The ratio of eligible regulation offered to regulation required averaged 1.90 throughout 2007.

- Demand. PJM calculates the regulation requirement each day for the entire day using 1.0 percent of the forecast-peak load for its control area. This requirement was established in August 2006. Because it is a function of peak load, the regulation requirement is seasonal. The average hourly regulation demand in 2007 was 967 MW. For the winter the demand was 956 MW; for the spring it was 913 MW; for the summer it was 1,089 MW; and for the fall it was 911 MW.

- Market Concentration. During 2007, the PJM Regulation Market had a load-weighted, average Herfindahl-Hirschman Index (HHI) of 1281 which is classified as "moderately concentrated."[5] The minimum hourly HHI was 720 and the maximum hourly HHI was 2547. The largest hourly market share in any single hour was 43 percent, and 56 percent of all hours had a maximum market share greater than 20 percent. In 2007, 80 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these results that the PJM Regulation Market in 2007 was characterized by structural market power in 80 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 two dominant suppliers, whose offers are capped at marginal cost plus $7.50 per MWh plus LOC. All suppliers are paid the market-clearing price.

4 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).

5 See the *2007 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 2007 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 $36.86. This represents an increase of $4.17 from the average price for regulation during 2006. In 2007, 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 26 percent of all hours.

Synchronized Reserve Market

In February 2007, PJM restructured the Synchronized Reserve Market.[6] Throughout 2006 and for January 2007, PJM had four zonal Synchronized Reserve Markets: the PJM Mid-Atlantic Region, the ComEd Control Zone, the PJM Western Region and the PJM Southern Region. On February 1, 2007, the PJM Mid-Atlantic Region, the ComEd Control Zone and the PJM Western Region were combined into one market called the RFC Synchronized Reserve Zone. The PJM Southern Region became the Southern Synchronized Reserve Zone. The RFC Synchronized Reserve Zone is governed by the reliability requirements of the Reliability*First* Corporation. The Southern Synchronized Reserve Zone (Dominion) reliability requirements are set by the Southeastern Electric Reliability Council (SERC).

Market Structure

- **Supply.** During January 2007, the offered and eligible excess supply ratio was 1.28 for the PJM Mid-Atlantic Synchronized Reserve Region and the ratio was 1.24 for the ComEd Synchronized Reserve Control Zone.[7] During February to December 2007, the offered and eligible excess supply ratio was 1.81 for the RFC Synchronized Reserve Zone and the ratio was 1.25 for the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone. 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 2007, the MW contribution of DSR resources to the Synchronized Reserve Market had become significant.

- **Demand.** The average synchronized reserve requirements were: 1,300 MW for the RFC Synchronized Reserve Zone and 1,160 MW for the Mid-Atlantic Subzone. For the Southern Synchronized Reserve Zone, the requirement was usually 0 MW. 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 Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone was 184 MW. The average demand for Tier 2 synchronized reserve in the Southern Synchronized Reserve Zone was 4 MW.

6 In PJM, the term, Synchronized Reserve Market, is used to refer only to Tier 2 synchronized reserve.

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

- Market Concentration. In 2007, market concentration was high in the Tier 2 Synchronized Reserve Markets. The average cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone throughout 2007 was 4151. The largest hourly market share was 100 percent and 76 percent of all hours had a maximum market share greater than 40 percent. In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, in 2007, 58 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these results that the PJM Synchronized Reserve Markets in 2007 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 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 in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market was $16.28 per MW in 2007, a $1.71 per MW increase from 2006.

- Price and Cost. 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. The increase in out-of-market purchases indicates that the Synchronized Reserve Market is not functioning to coordinate supply and demand. It is not clear why the additional synchronized reserve requirements cannot be procured via the market. If these requirements cannot be procured via the market, it is not clear why the out-of-market purchase of spinning reserve resources for local issues should not be treated as operating reserve charges. While the creation of the Synchronized Reserve Market for the entire RFC Zone suggested that there is a single, geographic market, the actual results are not consistent with that view.

- DSR. Demand-side resources began participating in the Synchronized Reserve Markets in August 2006. Participation of demand response grew significantly in 2007. Not only did more participants offer DSR, but demand response was generally less expensive than other forms of synchronized reserve. In 19 percent of hours during 2007 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 2007.

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 addition, in 2007, as in 2006, 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. The MMU's reliance on estimates of regulation costs 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.

The MMU has also consistently concluded that PJM's consolidation of its Regulation Markets had 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.[8, 9] This conclusion holds true for the 2007 Regulation Market. 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, 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 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.[10]

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 two 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, 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

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

9 *2006 State of the Market Report* (March 8, 2007), p. 247.

10 See the *2007 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test."

concentration and inelastic demand. (The term, Synchronized Reserve Market, refers only to Tier 2 synchronized reserve.) 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 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.

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. Beginning in October and increasing substantially in November and December, there was an increase in the amount of combustion-turbine-based, synchronized condenser MW added by PJM market operations to the Synchronized Reserve Market after market clearing. MW added after the market cleared accounted for more than 50 percent of total synchronized reserve MW purchased in December.

The increase in out-of-market purchases indicates that the Synchronized Reserve Market is not functioning to coordinate supply and demand. It is not clear why the additional synchronized reserve requirements cannot be procured via the market. If these requirements cannot be procured via the market, it is not clear why the out-of-market purchase of spinning reserve resources for local issues should not be treated as operating reserve charges. While the creation of the Synchronized Reserve Market for the entire RFC Zone suggested that there is a single, geographic market, the actual results are not consistent with that view.

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. The MMU concludes that the Synchronized Reserve Markets' results were competitive.

Regulation Market

Market Structure

The market structure of the 2007 PJM Regulation Market remained similar to the market structure of the 2006 Regulation Market. DSR participation was introduced in 2006, but demand-side resources did not qualify and make offers in the Regulation Market in either 2006 or 2007.

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 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.

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 2007 was 1.90. 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 *2007 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.[11] During 2007 the PJM regulation requirements ranged from 709 MW to 1,390 MW. The average required regulation was 967 MW.

Market Concentration

Market Structure Definitions

The market structure analysis follows the FERC logic specified in the AEP Order.[12] The logic of the delivered price test is followed by calculating market share, HHI and pivotal supplier metrics for each market configuration.[13] 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 the 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. 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.

11 See Reliability*First* Corporation <http://www.rfirst.org/> .

12 107 FERC ¶ 61,018 (2004) (AEP Order) and 108 FERC ¶ 61,026 (2004) (AEP Order on Rehearing).

13 AEP Order at 105 et seq.

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

During 2007 the PJM Regulation Market total capability was 7,609 MW.[14] 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 both offered and eligible to participate on an hourly level in the market were lower than the total regulation capability. In 2007 the average daily offer level was 3,911 MW or 51 percent of total capability while the average hourly eligible offer level was 1,835 MW or 24 percent of total 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 2007

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent Of Capability Offered	Average Hourly Eligible (MW)	Percent Of Capability Eligible
All hours	7,609	3,911	51%	1,835	24%
Off peak	7,609	NA	NA	1,575	21%
On peak	7,609	NA	NA	2,118	28%

The ratio of the hourly regulation supply offered and eligible to the hourly regulation requirement averaged 1.90 for PJM during 2007. When this ratio equals 1.0, it indicates that offered supply exactly equals demand for the referenced time period.

Hourly HHI values were calculated based on cleared regulation. HHI values ranged from a maximum of 2547 to a minimum of 720, with an average value of 1281 which is defined as moderately concentrated by the FERC definitions. Table 6-2 summarizes the 2007 PJM Regulation Market HHIs.

Table 6-2 PJM cleared regulation HHI: Calendar year 2007

Market Type	Minimum	Load-Weighted Average	Maximum
Cleared regulation	720	1281	2547

14 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.

The PJM Regulation Market exhibited consistent moderate market concentration with about 4.1 percent of the periods with an HHI less than 1000 and about 2.4 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 HHI: Calendar year 2007

The largest hourly market share for cleared regulation was 43 percent, and 56 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 16 percent. Annual average hourly market shares for cleared regulation in 2007 are listed in Table 6-3.

Table 6-3 Highest annual average hourly Regulation Market shares: Calendar year 2007

Company Market Share Rank	Cleared Regulation Top Market Shares
1	16%
2	13%
3	12%

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, 68 percent of hours failed the one pivotal supplier test during 2007. (See Table 6-4.) This means that for 68 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 88 percent of the hours with one pivotal supplier; a second company was pivotal in 74 percent of hours with one pivotal supplier, and a third company was pivotal in 73 percent of hours when there was one pivotal supplier. Ninety-four percent of hours failed the three pivotal supplier test. One supplier of regulation was pivotal in 90 percent of the three pivotal supplier hours and two other companies were pivotal in 76 percent of three pivotal supplier hours.

Table 6-4 Regulation Market pivotal suppliers: Calendar year 2007

	Hours with One Pivotal Supplier (Percent)	Hours with Three Pivotal Suppliers (Percent)
Price ≤ RMCP • 1.05	68%	94%
Price ≤ RMCP • 1.5	14%	80%

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, 14 percent of hours failed the one pivotal supplier test during 2007. (See Table 6-4.) Eighty percent of hours failed the three pivotal supplier test. One company was pivotal in 92 percent of those hours; a second company was pivotal in 80 percent, and a third company was pivotal in 76 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 remained persistent and repeated during 2007.[15]

The MMU concludes from these results that the PJM Regulation Market in 2007 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.

Market Conduct

Offers

Generators wishing to participate in the PJM Regulation Market must submit regulation offers for specific units by 1800 Eastern Prevailing Time (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.

15 See the *2006 State of the Market Report*, Section 6, “Ancillary Services,” p. 248.

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 (i.e., 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 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.[16] 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; 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. The Regulation Market price that results is the RMCP, and the unit that sets this price is the marginal unit.

In 2007, 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. In April 2007, the Cost Development Task Force (CDTF) proposed adjusting the formulas used to calculate regulating unit costs.[17] The new rules allow units which have been regulating for less than 10 years to add variable operating and maintenance (VOM) costs according to unit type. These adjustments have increased the variable operating and maintenance costs some units are permitted to use, thus decreasing the percentage of bids which exceed the allowable $7.50 plus costs in 2007 from the 33 percent in 2006. Using the proposed CDTF guidelines, the MMU estimated hourly marginal costs for units that provided regulation during 2007.[18] Based on those estimates, 26 percent of marginal unit daily offers exceeded marginal costs.

16 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.

17 See PJM Cost Development Task Force < http://www.pjm.com/committees/task-forces/cdtf/postings/20070416-regulation-redline.pdf > (56 KB).

18 See PJM. "Manual 15: Cost Development Guidelines," Revision 8 (October 16, 2007), p. 40.

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.[19]

In 2007, offers at levels greater than the competitive level set the clearing price for regulation in 26 percent of hours.[20] Seventeen percent of hours were between $0 and $7.50 per MW above the competitive level; 1 percent of hours were between $7.50 and $10 per MW above the competitive level; and 7 percent of hours 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 2007 was $12.06, so an additional $7.50 per MW is a markup of approximately 62 percent. These results mean that the MMU cannot conclude that the Regulation Market results were competitive in 2007 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.[21]

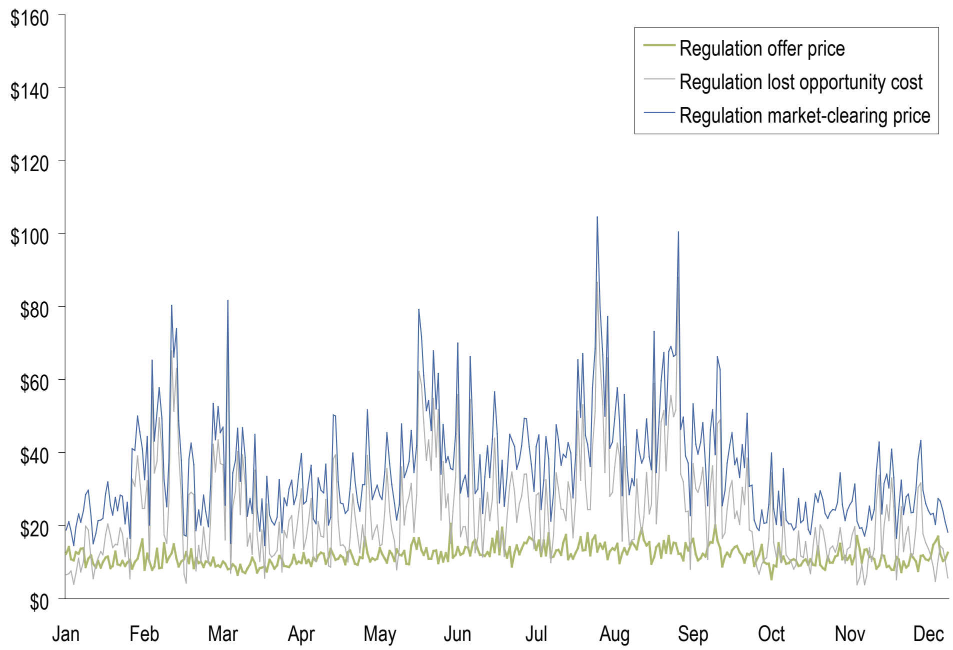
19 See PJM. "Manual 28: Operating Agreement, Accounting," Revision 39, Section 4, "Regulation Credits" (January 1, 2008), pp. 27-28. PJM uses estimated opportunity cost to clear the market and real-time opportunity cost to compensate generators that provide regulation and synchronized reserve. Real-time opportunity cost is calculated using real-time LMP.

20 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.

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

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 units are paid RMCP times their assigned regulation MW, 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 2007 was $12.06 per MW. The load-weighted, average LOC of the marginal unit for the PJM Regulation Market during 2007 was $24.85. In the PJM Regulation Market the marginal unit LOC averaged 67 percent of the RMCP.

Figure 6-2 PJM Regulation Market daily average market-clearing price, lost opportunity cost and offer price (Dollars per MW): Calendar year 2007

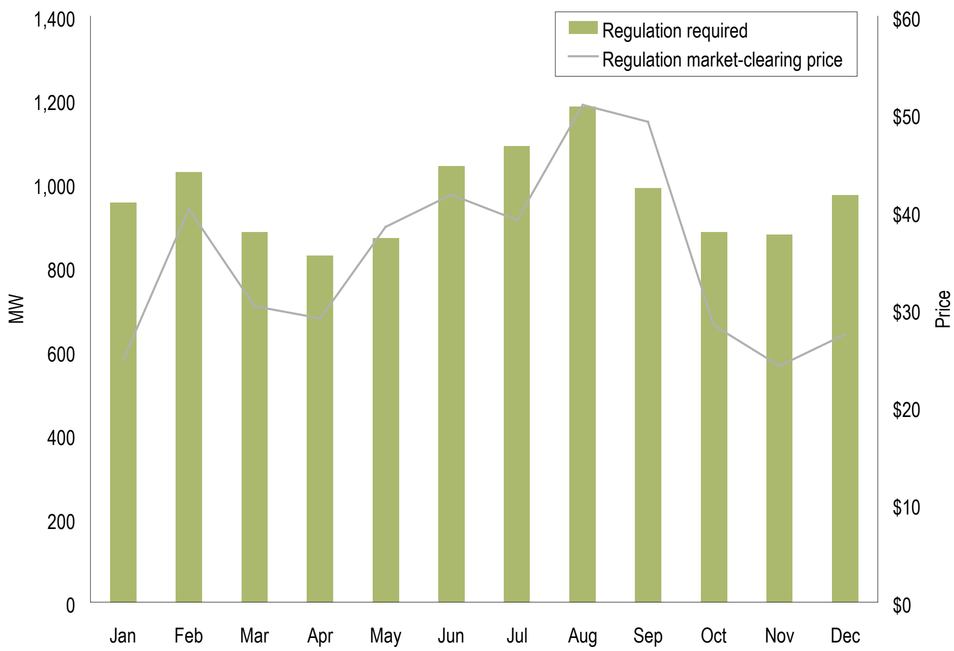


On a shorter-term basis, regulation prices follow daily and weekly patterns. The supply of regulation is most plentiful between 0600 and 2300 EPT, Monday through Friday.

During weekends and North American Electric Reliability Council (NERC) holidays, and weekdays between the hour ending at 2400 until the hour ending at 0700 (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.

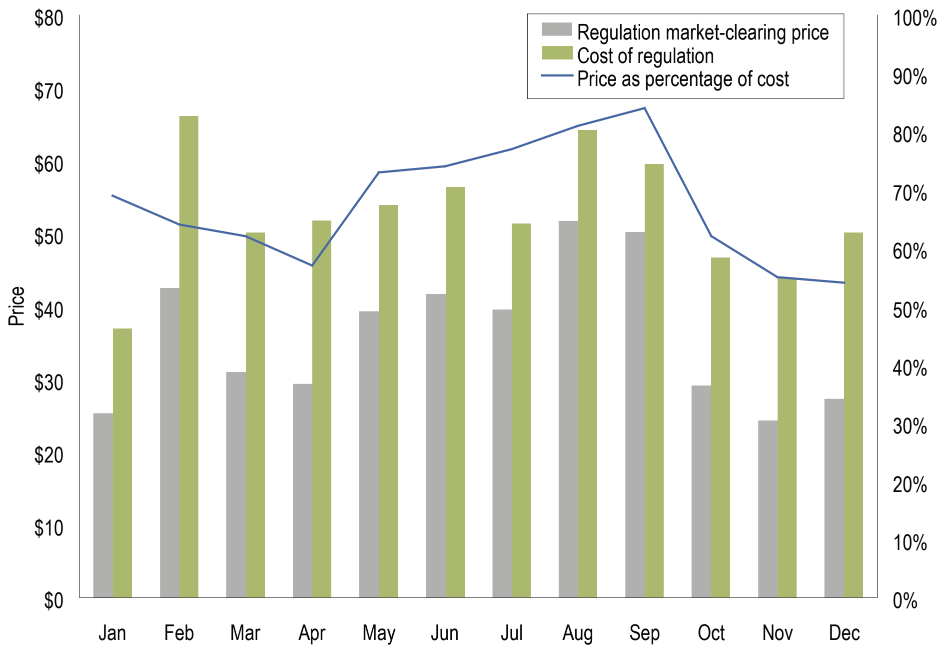
Figure 6-3 shows the level of demand for regulation by month in 2007 and the corresponding level of regulation price. The data show a correlation between price and demand.

Figure 6-3 Monthly average regulation demand (required) vs. price: Calendar year 2007



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 Monthly load-weighted, average regulation cost and price: Calendar year 2007



For all of 2007, the load-weighted, average regulation price was $36.86. The average regulation charge was $52.91. The difference between the Regulation Market price and the actual charge for regulation remained significant in 2007. The charge for regulation was 43.5 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

The PJM Synchronized Reserve Market was restructured in 2007. The Mid-Atlantic Region's Synchronized Reserve Market, the Western Region's Synchronized Reserve Market, and the ComEd Control Zone's Synchronized Reserve Market were combined into a single market called the RFC Synchronized Reserve Zone. 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.

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.[22] 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 reserve resources. This market is termed the Synchronized Reserve Market. Several steps are necessary before the hourly

22 See PJM. "Manual 11: Balancing Operations," Revision 32 (September 28, 2007), p. 39.

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.[23]

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.[24, 25] 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.

During January 2007, the offered and eligible excess supply ratio was 1.28 for the PJM Mid-Atlantic Synchronized Reserve Region and the ratio was 1.24 for the ComEd Synchronized Reserve Control Zone.[26] For the RFC Synchronized Reserve Zone during February through December 2007, the offered and eligible excess supply ratio was 1.81. Within the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone, the offered and eligible excess supply ratio was 1.25.[27] 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. 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.[28]

23 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.

24 See PJM. "Manual 11: Balancing Operations," Revision 32 (September 28, 2007), p. 41.

25 See PJM. "Manual 15: Cost Development Guidelines," Revision 8 (October 16, 2007), p. 37.

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

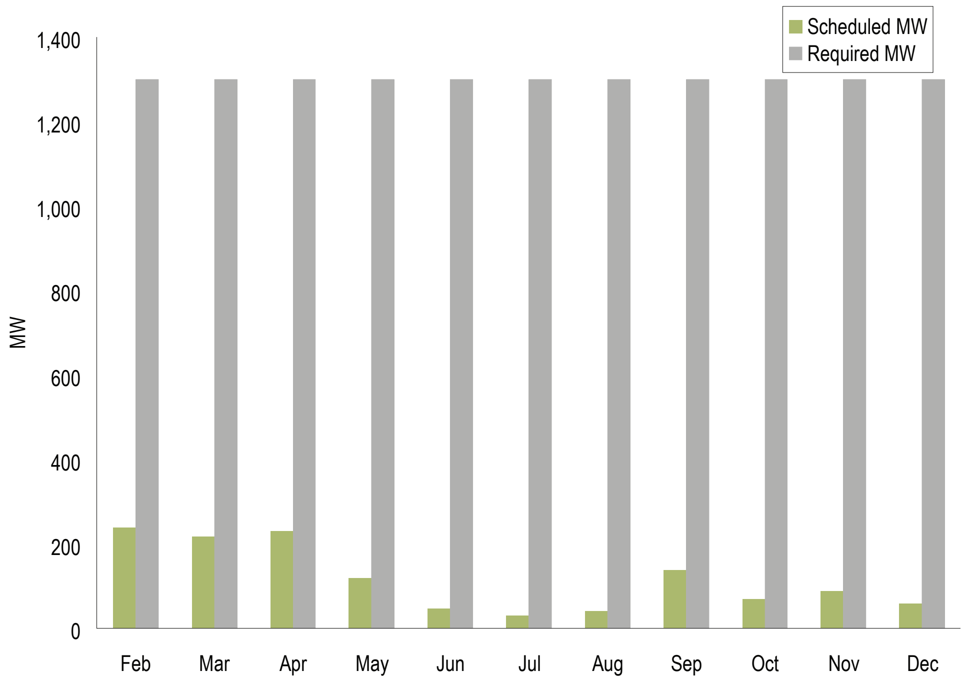
27 The Synchronized Reserve Market in the PJM Southern Region cleared in so few hours that related data for that market are not meaningful.

28 See PJM. "Manual 10: Pre-Scheduling Operations," Revision 22 (May 15, 2007), p. 21.

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 February through December 2007 was always 1,300 MW.

Figure 6-5 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during 2007 for the RFC Synchronized Reserve Market.[29]

Figure 6-5 RFC Synchronized Reserve Zone monthly required vs. scheduled: February through December 2007



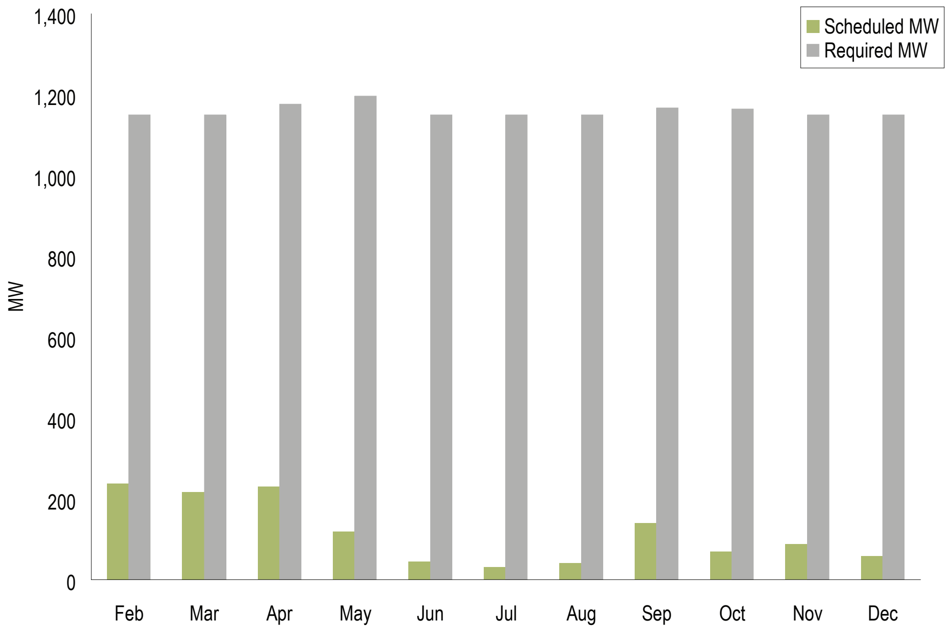
The RFC Synchronized Reserve Zone is large and some available Tier 1 must be physically located in the Mid-Atlantic Subzone as a result of transmission limits between the western and eastern portions of the zone. PJM calculates the available transfer capability of these limits. The calculation of Mid-Atlantic 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.[30] As a result, there is frequently a Tier 2 synchronized reserve requirement only in the Mid-Atlantic Subzone. In this case, the Mid-Atlantic Subzone has a separate clearing price.

As a whole, the RFC Synchronized Reserve Zone almost always has enough Tier 1 to cover its synchronized reserve requirement. In 2007, the RFC Synchronized Reserve Zone cleared a Tier 2 Synchronized Reserve Market in less than 1 percent of all hours. The Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone cleared a separate Tier 2 market during 60 percent of all hours. Figure 6-6 compares the required Tier 2 MW to the scheduled MW for the Mid-Atlantic Subzone only.

29 Figures 6-5 through 6-12 address the combined synchronized reserve markets (February 2007 through December 2007 only).

30 See PJM. "Manual 11: Scheduling Operations," Revision 32 (September 28, 2007), p. 45.

Figure 6-6 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone synchronized reserve required vs. scheduled: February through December 2007



The actual synchronized reserve requirement for the Mid-Atlantic Subzone for February through December 2007 was usually 1,150 MW but there were several days in April, May, September and October on which those requirements were increased for reliability reasons related to temporary grid conditions.

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 shows that almost all Tier 2 Synchronized Reserve Market MW are Mid-Atlantic Subzone, Synchronized Reserve Market MW.

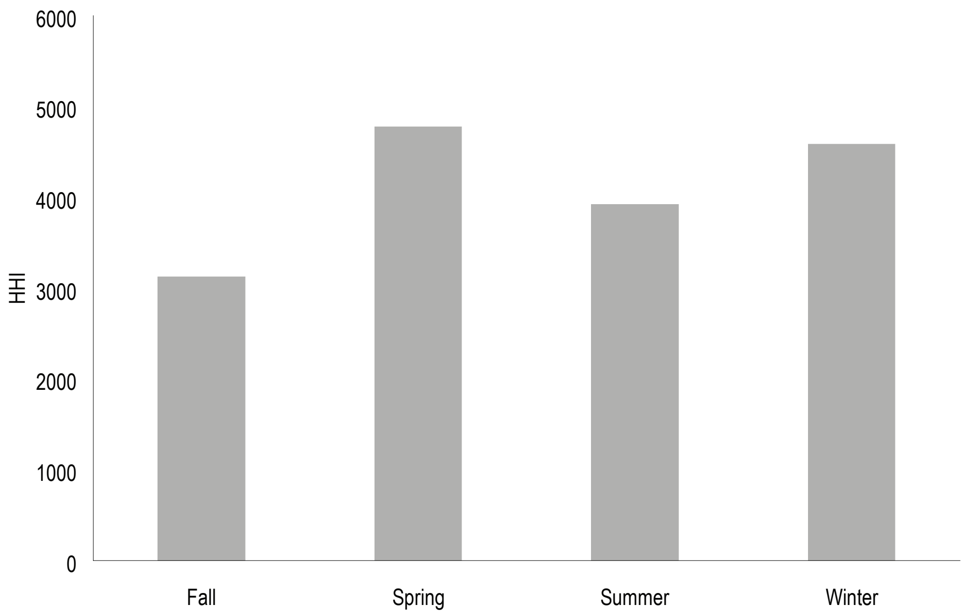
The Southern Synchronized Reserve Zone is part of the Virginia and Carolinas Area (VACAR) subregion of SERC. VACAR specifies that available, 15-minute quick start reserve can be subtracted from Dominion's share of the largest contingency to determine synchronized reserve requirements. The amount of 15-minute 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 4 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 2007 than the four PJM Tier 2 Synchronized Reserve Markets had been in 2006, the 2007 RFC Synchronized Reserve Market remains highly concentrated and dominated by a relatively small number of companies.

The HHI for the Mid-Atlantic Subzone of the 2007 RFC Synchronized Reserve Market was 4151, which is defined as highly concentrated. (See Figure 6-7 which also provides seasonal details.)

Figure 6-7 Cleared Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market seasonal HHI: February through December 2007



The largest hourly market share was 100 percent and 76 percent of all hours had a maximum market share greater than 40 percent. In 1 percent of Mid-Atlantic Subzone hours during which a market was cleared between February and December 2007 a single company had 100 percent of the market share. The highest annual average market share was 26 percent. (See Table 6-5.)

Table 6-5 The Mid-Atlantic Subzone of the PJM RFC Tier 2 Synchronized Reserve Market's cleared market shares: February through December 2007

Company Market Share Rank	Cleared Synchronized Reserve: All Units
1	26%
2	18%
3	8%
4	7%
5	4%

The pivotal supplier metric provides an analytical approach to the issue of excess supply.[31] (See Table 6-6.)

Table 6-6 The Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market percent pivotal supplier hours: February through December 2007

	Hours with One Pivotal Supplier (Percent)	Hours with Three Pivotal Suppliers (Percent)
Price ≤ RMCP • 1.05	41%	87%
Price ≤ SRMCP • 1.5	10%	58%

When the relevant market was defined to include all offers at less than, or equal to, 1.05 times the clearing price, there was a single pivotal supplier in 41 percent of the hours and three pivotal suppliers in 87 percent of the hours.

When the relevant market is defined to include all offers at less than, or equal to, 1.5 times the clearing price in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, there was a single pivotal supplier in 10 percent of the hours and three pivotal suppliers in 58 percent of the hours. One company was pivotal in 73 percent of three pivotal supplier hours and a second company was pivotal in 66 percent of those 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.

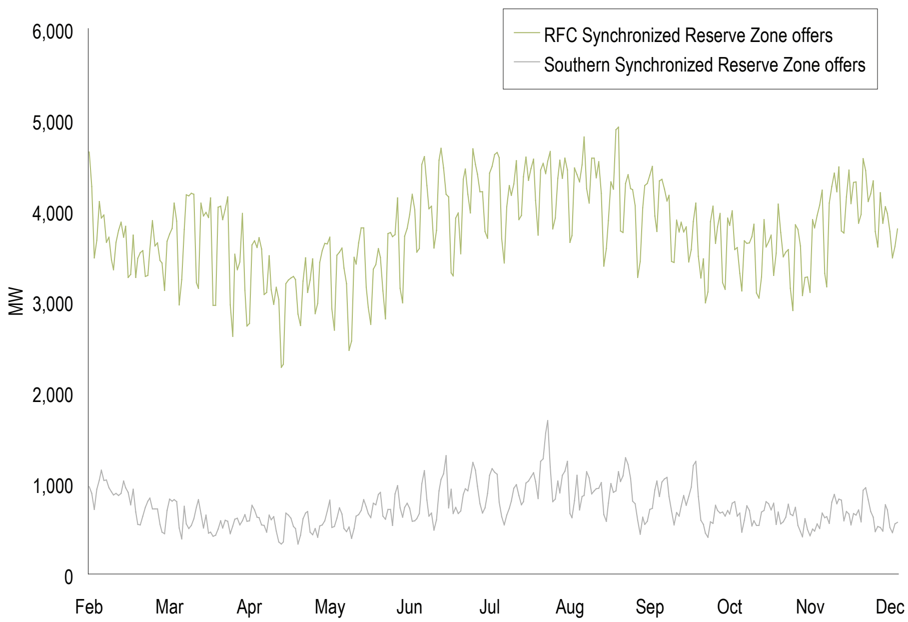
31 See the *2007 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test."

Market Conduct

Offers

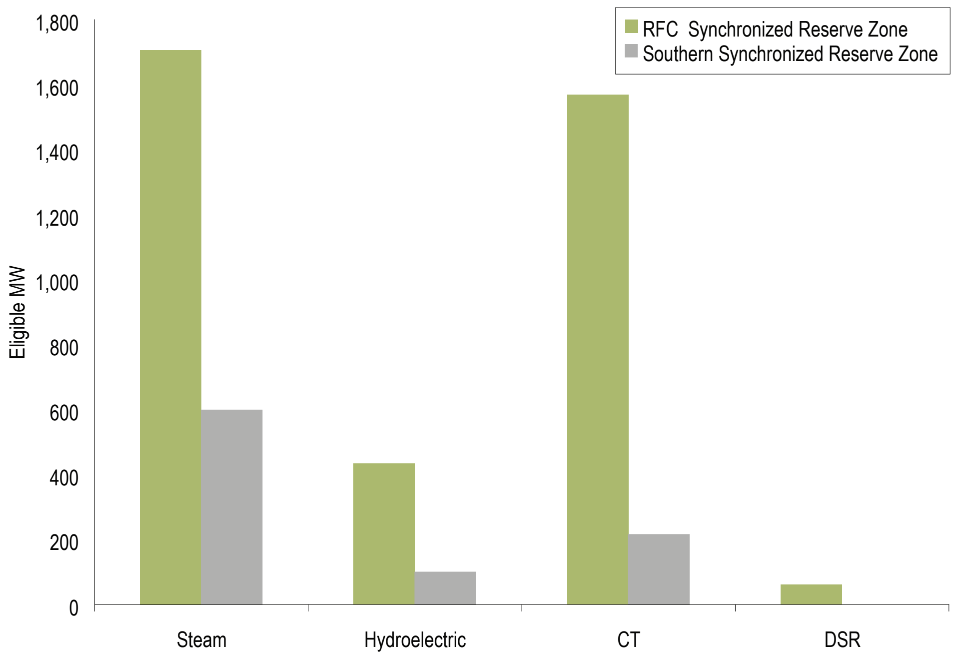
Figure 6-8 shows the daily average hourly eligible Tier 2 synchronized reserve offers. Eligible offer MW is dependent upon the offering unit being run. For that reason, the eligible offer volume shows weekly variability based on off-peak/on-peak operating cycles as well as seasonal variability.

Figure 6-8 Tier 2 synchronized reserve average hourly eligible volume (MW): February through December 2007



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

Figure 6-9 Average daily Tier 2 synchronized reserve eligible by unit type (MW): February through December 2007



As of the end of 2007, the MW contribution of DSR resources to the Synchronized Reserve Market had become significant. In 2007, DSR supplied 19 percent of synchronized reserve MW cleared in the RFC Synchronized Reserve Zone. The DSR share of total synchronized reserve MW cleared grew throughout the year (See Figure 6-12) reaching 45 percent for the months of October, November and December. What are termed demand-side resources may at times be generation that is behind the meter.

Market Performance

Price

Figure 6-11 shows the load-weighted, average Tier 2 price (i.e., SRMCP • MW cleared) and the cost per MW associated with meeting PJM demand for synchronized reserve (i.e., total credits paid • MW purchased). 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 for only 10 hours in 2007. The only significant Synchronized Reserve Market was in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market. The load-weighted, average price for synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market during 2007 was \$16.28 while the corresponding cost of synchronized reserve was \$21.32.

Price and Cost

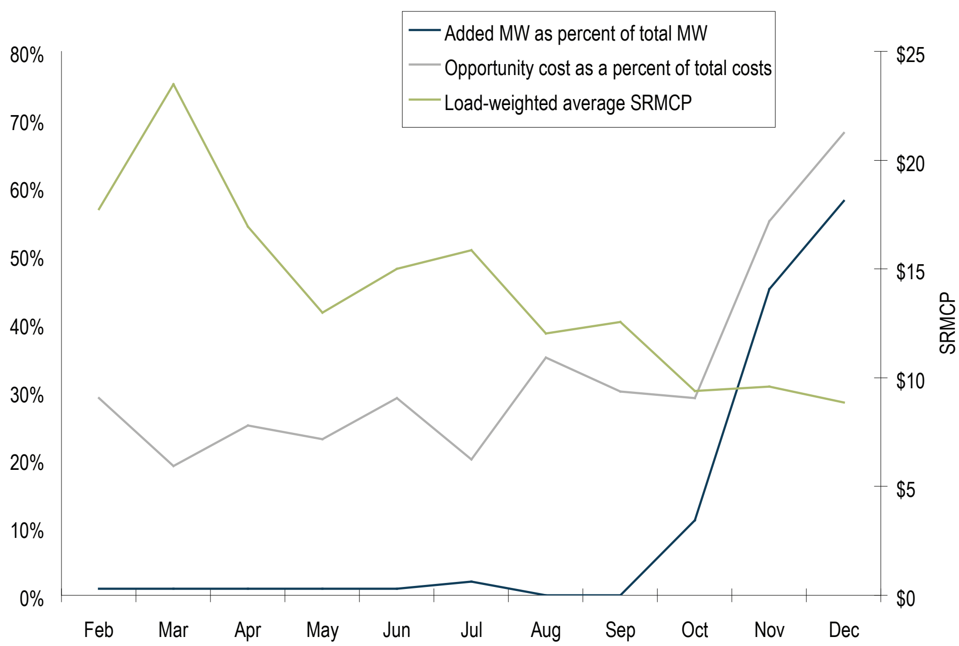
There was a significant change in the operation of the Synchronized Reserve Market in the last quarter of 2007 as PJM relied less on the market and more on out-of-market purchases of spinning reserve for local needs. Beginning in October and increasing substantially in November and December, there was an increase in the amount of CT-based, synchronized condenser MW added by PJM market operations to the Synchronized Reserve Market after market clearing. (See Figure 6-10 for added MW as a percent of total MW.) MW added after the market cleared accounted for more than 50 percent of total synchronized reserve MW purchased in 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 (LSEs) must pay. (See Figure 6-10 for load-weighted, average SRMCP.)

There was an increase in spinning reserve MW purchased by PJM for local needs in New Jersey, including those related to the operation of the Neptune transmission line to Long Island, beginning in midsummer 2007. These spinning reserve services were initially accounted for as operating reserve. Effective in October, PJM determined that these spinning reserve services should be included in the Synchronized Reserve Market rather than as operating reserve.

The increase in out-of-market purchases indicates that the Synchronized Reserve Market is not functioning to coordinate supply and demand. It is not clear why the additional synchronized reserve requirements cannot be procured via the market. If these requirements cannot be procured via the market, it is not clear why the out-of-market purchase of spinning reserve resources for local issues should not be treated as operating reserve charges. While the creation of the Synchronized Reserve Market for the entire RFC Zone suggested that there is a single, geographic market, the actual results are not consistent with that view.

This local dynamic contributes to the difference between the total costs to provide synchronized reserve and the market-clearing price.

Figure 6-10 Impact of synchronized condensing added to the combined Synchronized Reserve Market after market clearing: February through December 2007

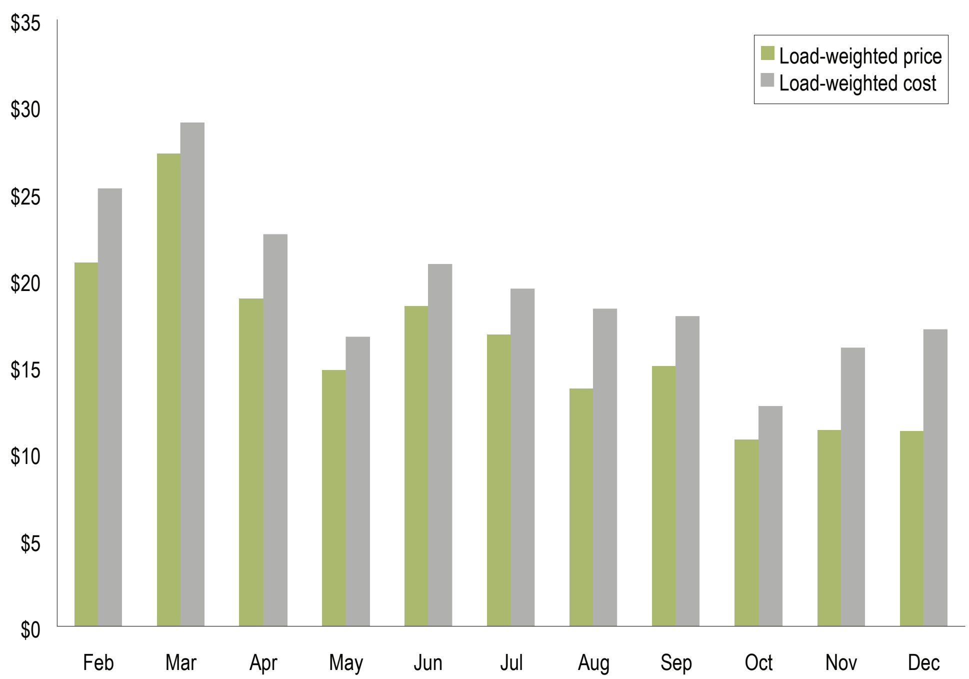


The addition of synchronized condensing MW to the Synchronized Reserve Market on an out-of-market basis means that the clearing price is below the efficient level for the defined market, or that the market is not correctly defined geographically and the price is below the efficient level for a more local market.

The difference between the Tier 2 Synchronized Reserve Market price and cost for Tier 2 synchronized reserve was less significant for the full year in 2007 than it had been in 2006. The difference in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market for 2007 between the monthly load-weighted, average price of Tier 2 synchronized reserve and cost of Tier 2 synchronized reserve was $5.04. The cost was 31 percent higher than the price. In 2006 the cost had been 49 percent higher than the price.

While there was a reduction in the annual difference between the cost and price of synchronized reserve, the difference began to increase at the end of 2007. The cost/price ratio was worse in the last three months of 2007 as a result of out-of-market purchases of synchronized reserve (See Figure 6-10).

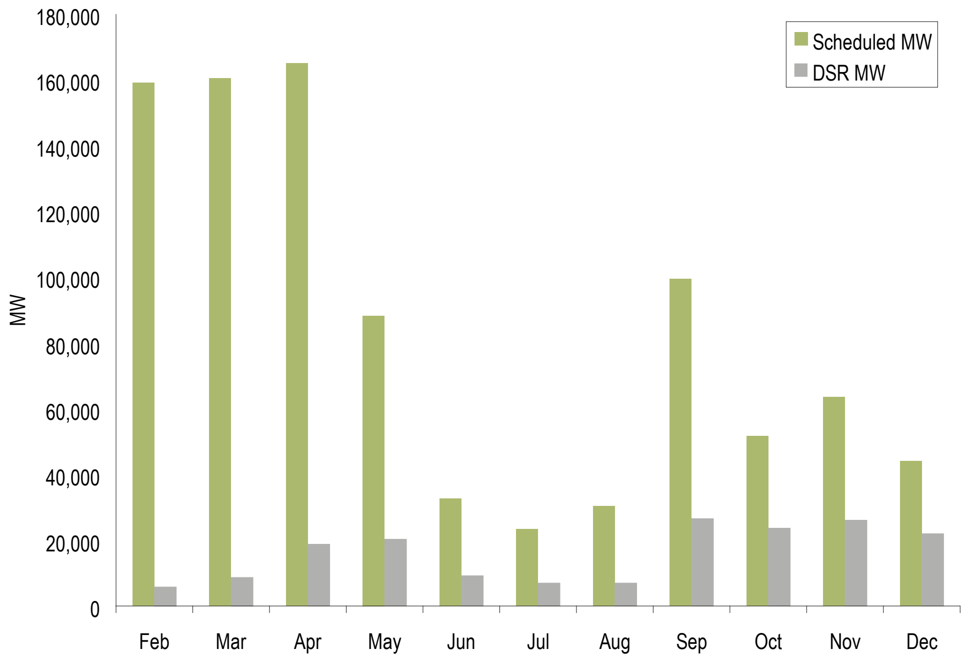
Figure 6-11 Comparison of RFC Tier 2 synchronized reserve price and cost (Dollars per MW): February through December 2007



DSR

Demand-side resources began participating in the Synchronized Reserve Markets in August 2006. Figure 6-12 shows total monthly synchronized reserve scheduled MW and cleared MW for DSR synchronized reserve. Participation of demand response grew significantly in 2007. Not only did more participants offer DSR, but demand response was generally less expensive than other forms of synchronized reserve. In 19 percent of hours during 2007 in which a Tier 2 Synchronized Reserve Market was cleared for the Mid-Atlantic Subzone, all synchronized reserve was provided by DSR.

Figure 6-12 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: February through December 2007



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 2007.