SECTION 5 – CAPACITY MARKET

Effective June 1, 2007, the PJM Capacity Credit Market (CCM), which had been the market design since 1999, was replaced with the RPM Capacity Market construct. For the *2007 State of the Market Report,* the Market Monitoring Unit (MMU) analyzed the market structure, participant conduct and market performance of both Capacity Market designs and compared the 2007 market results to 2006 and certain other prior years.[1]

Each organization serving PJM load must pay for the capacity resources required to meet its capacity obligations. Collectively, all arrangements by which load-serving entities (LSEs) acquire capacity are known as the Capacity Market.[2] Under the CCM, LSEs could acquire capacity resources by relying on the PJM Capacity Market, by constructing generation, or by entering into bilateral agreements. Under RPM, LSEs must pay the locational capacity price for their zone. LSEs can own capacity or purchase capacity bilaterally and can offer capacity into the RPM Auctions.

Overview

The MMU analyzed market structure and market performance in the PJM Capacity Market for calendar year 2007, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability. The analyses of the two market designs are presented separately, but there is substantial overlap in the basic elements of the Capacity Markets.

Capacity Credit Market

Market Design

The PJM CCM provided mechanisms to balance the supply of and demand for capacity unmet by the bilateral market or self-supply.[3] The CCM consisted of the Daily, Interval, Monthly and Multimonthly CCM.[4] The CCM was intended to provide a transparent, market-based mechanism for retail LSEs to acquire the capacity resources needed to meet their capacity obligations and to sell capacity resources when no longer needed to serve load. The Daily CCM permitted LSEs to match capacity resources with short-term shifts in retail load while the Interval, Monthly and Multimonthly CCMs provided mechanisms to match longer-term obligations to serve load with capacity resources.

Market Structure

- Supply. Unforced capacity remained relatively constant in the CCM in January through May 2007 compared to 2006.[5] Average unforced capacity increased by 377 MW or 0.2 percent to 152,859 MW.[6]

1 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." For additional information on the phased integration into the PJM CCM of the ComEd Control Zone, see the *2006 State of the Market Report*, Volume II, Appendix E, "Capacity Market."

2 See the *2007 State of the Market Report*, Volume II, Appendix M, "Glossary" and Appendix N, "Acronyms" for definitions of PJM Capacity Market terms.

3 All PJM Capacity Market values (capacities) are in terms of unforced MW.

4 PJM defined three intervals for its CCM. The first interval extended for five months and ran from January through May. The second interval extended for four months and ran from June through September. The third interval extended for three months and ran from October through December.

5 For information on the CCM during 2006, see the *2006 State of the Market Report*, Volume II, Section 5, "Capacity Market."

6 Calculated values shown in Section 5, "Capacity Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

Capacity resources exceeded capacity obligations every day by an average of 9,450 MW, a decrease of 81 MW from the average net excess of 9,531 MW for 2006.

- **Demand.** Unforced obligations also remained relatively constant in the PJM CCM in January through May 2007 compared to 2006. Average load obligations increased by 458 MW or 0.3 percent to 143,409 MW. PJM electricity distribution companies (EDCs) and their affiliates maintained an 80.8 percent market share of load obligations in the PJM CCM in January through May 2007, down from 87.6 percent for 2006.

- **Market Concentration.** Structural analysis of the PJM Capacity Market during the January through May period found significant market structure issues both in the CCM and the overall ownership of capacity. All daily auctions failed the three pivotal supplier (TPS) test; 97.4 percent of daily auctions failed the single pivotal supplier test and 83.3 percent of monthly auctions failed the single pivotal supplier test. Total capacity ownership also failed the single pivotal supplier test throughout the period, with three individual suppliers who were each pivotal on a stand-alone basis.

- **Imports and Exports.** In January through May 2007, imports averaged 2,794 MW, which was a decrease of 299 MW or 9.7 percent from the 2006 average of 3,093 MW. Exports averaged 4,939 MW, which was a decrease of 19 MW or 0.4 percent from the 2006 average of 4,958 MW. Average net exchange increased by 280 MW or 15.0 percent to -2,145 MW from the 2006 average of -1,865 MW. Internal bilateral transactions averaged 163,009 MW, which was an increase of 2,057 MW or 1.3 percent from the 160,952 MW average for 2006.

- **Active Load Management (ALM).** In January through May 2007, ALM credits in the PJM CCM averaged 1,677 MW, down 151 MW (8.3 percent) from 1,828 MW in 2006.

Market Performance

- **CCM Prices and Volumes.** During January through May 2007, total PJM CCM prices averaged $3.21 per MW-day, which was $2.52 per MW-day less than the 2006 average of $5.73 per MW-day. Total PJM CCM transactions averaged 11,727 MW (8.2 percent of obligation), 2,609 MW higher than the 2006 average of 9,118 MW (6.4 percent of obligation).

  For calendar year 2006, capacity resources across the entire regional transmission organization (RTO) were valued at a total of $299.0 million. This equals the total capacity obligation valued at the combined-market, weighted-average CCM clearing price for 2006.

RPM Capacity Market

Market Design

On June 1, 2007, the RPM Capacity Market design was implemented in the PJM region, replacing the CCM Capacity Market design that had been in place since 1999.[7] The RPM market design differs from the CCM market design in a number of important ways. The RPM is a forward-looking, annual, locational market, with a must-offer requirement for capacity and mandatory participation by load, with performance incentives for generation, that includes clear, market power mitigation rules and that permits the direct participation of demand-side resources. CCM, in contrast, was a daily, single-price, voluntary balancing market that included less than 10 percent of total PJM capacity, that had weak performance incentives, that had no explicit market power mitigation rules and that did not permit the participation of demand-side resources.

Under RPM, capacity obligations are annual. Under CCM, capacity obligations were daily. Under RPM, auctions are held for delivery years that are three years in the future. Under CCM daily, monthly and multimonthly auctions were held. Under RPM, prices are locational and may vary depending on transmission constraints.[8] Under CCM, prices were the same, regardless of location. Under RPM, sell offers are unit-specific. Under CCM, offers were non-unit-specific capacity credits. Under RPM, existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for the fixed resource requirement (FRR) option. Under CCM, there was no must-offer rule after June 2000. Under RPM, participation by LSEs is mandatory, except for the FRR option. Under CCM, there was no mandatory participation in the CCM auctions.[9] Under RPM, there is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices. Under CCM the demand was defined by participant buy bids. Under RPM there are performance incentives for generation. Under CCM the only performance incentive was the direct relationship between historical equivalent demand forced outage rate (EFORd) and the amount of capacity that could be sold. Under RPM there are explicit market power mitigation rules that define structural market power, that define offer caps based on the marginal cost of capacity and that do not limit prices offered by new entrants. Under CCM, there were no explicit market power mitigation rules. Under RPM, demand-side resources may be offered directly into the auctions and receive the clearing price. Under CCM, demand-side resources could not be offered directly into the market.

Market Structure

- Supply. Total internal capacity increased from 154,985.5 MW on January 1, 2007, to 155,206.0 MW on June 1, 2007, or 220.5 MW. This increase was the result of 573.2 MW from demand response (DR) offered into the auction, offset in part by 332.6 MW from higher EFORds and 20.1 MW from generation deratings. No new generation was offered into the 2007/2008 RPM Auction.

7 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2007 State of the Market Report*, Volume II, Section 5, "Capacity Market" and include all capacity within the PJM footprint.

8 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

9 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Schedule 8.1 (June 1, 2007) (Accessed July 19, 2007) <http://www.pjm.com/documents/downloads/agreements/raa.pdf> (1.92 MB).

In the 2008/2009 and 2009/2010 auctions, new generation increased 528.6 MW; 112.6 MW were brought out of retirement and net generation uprates were 220.3 MW, for a total of 861.5 MW. DR offers increased 815.9 MW through June 1, 2009. Net improvements in EFORds added 434.8 MW. The net effect from May 31, 2007, through June 1, 2009, was an increase in total internal capacity of 2,350.6 MW (1.5 percent) from 154,967.6 MW to 157,318.2 MW.

In the 2008/2009 auction, 15 more generating units made offers than in the 2007/2008 RPM Auction. The increase included five new wind units (66.1 MW), three new diesel units (23.3 MW) and two units (112.6 MW) which came out of retirement while the remaining five units were the result of a reclassification of external units.

In the 2009/2010 auction, 17 more generating units made offers than in the 2008/2009 RPM Auction. The increase included eight new combustion turbine (CT) units (380.2 MW), two new diesel units (9.2 MW) and one new steam unit (49.8 MW) while the remaining six units included more units imported, fewer units exported, a decrease in units excused from offering into the auction and fewer units removed from the auction under the fixed resource requirement (FRR) option.

- Demand. There was a 5,298.6 MW increase in the RPM reliability requirement, which is similar to the obligation under CCM, from 142,978.7 MW on January 1, 2007, to 148,277.3 MW on June 1, 2007. On June 1, 2007, PJM EDCs and their affiliates maintained a 77.5 percent market share of load obligations under RPM, down from an average of 80.8 percent for the first five months of 2007 under CCM.

- Market Concentration. For the 2007/2008, 2008/2009 and 2009/2010 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In each auction all participants in the total PJM market as well as the locational deliverability area (LDA) markets failed the three pivotal supplier (TPS) market structure test. The result was that offer caps were applied to all sell offers in all three auctions.

- Imports and Exports. Net exchange, which is imports less exports, decreased 707.6 MW from January 1, to June 1, 2007, as the result of a decrease in exports of 682.9 MW and an increase in imports of 24.7 MW.

- Demand-Side Resources. Under RPM, demand-side resources in the Capacity Market, a combination of DR offered into the RPM Auctions and certified/forecast interruptible load for reliability (ILR), increased from the 1,676.7 MW in the CCM ALM program by 87.2 MW on June 1, 2007, by an additional 882.2 MW on June 1, 2008, and an additional 354.3 MW on June 1, 2009. The ALM volumes were MW credits against the obligation while the LM volumes are treated as capacity resources.

- Net Excess. Net excess as calculated under CCM decreased 4,370.5 MW from 10,169.9 MW on January 1, to 5,799.4 MW on June 1, 2007. Net excess as calculated under RPM was 5,240.5 MW or 558.9 MW less than the 5,799.4 MW as calculated under CCM on June 1, 2007.

Market Conduct

- 2007/2008 RPM Auction. Of the 1,061 generating units which submitted offers, unit-specific offer caps were calculated for 125 units (11.8 percent). Offer caps of all kinds were used by 566 units (53.4 percent), of which 388 were the default (proxy) offer caps calculated and posted by the MMU. The remaining 495 units were price takers, of which the offers for 492 units were zero and the offers for three units were set to zero because no data were submitted. Fifteen DR resources offered into the auction.

- 2008/2009 RPM Auction. Of the 1,076 generating units which submitted offers, unit-specific offer caps were calculated for 117 units (10.9 percent). Offer caps of all kinds were used by 567 units (52.7 percent), of which 399 were the default (proxy) offer caps calculated and posted by the MMU.

- 2009/2010 RPM Auction. Of the 1,093 generating units which submitted offers, unit-specific offer caps were calculated for 151 units (13.8 percent). Offer caps of all kinds were used by 550 units (50.3 percent), of which 377 were the default (proxy) offer caps calculated and posted by the MMU.

Market Performance

2007/2008 RPM Auction

- RTO. Total internal RTO unforced capacity of 155,206.0 MW includes all generating units and DR that qualified as a PJM capacity resource for the 2007/2008 RPM Auction, excludes external units and reflects owners' modifications to installed capacity (ICAP) ratings. Including FRR, committed resources and imports, RPM capacity was 135,092.6 MW. The 129,409.2 MW of cleared resources for the entire RTO represented a reserve margin of 19.8 percent, which was 3,604.2 MW greater than the reliability requirement of 125,805.0 MW (installed reserve margin (IRM) of 15.0 percent) and resulted in a clearing price of $40.80 per MW-day.

  Total resources in the RTO were 129,409.2 MW which resulted in a net excess of 5,240.5 MW, a decrease of 3,693.6 MW from the net excess of 8,934.1 MW on May 31, 2007. Certified interruptible load for reliability (ILR) was 1,636.3 MW.

  Cleared resources across the entire RTO will receive a total of $4.3 billion based on the unforced MW cleared and the prices in the 2007/2008 RPM Auction.

- Eastern Mid-Atlantic Area Council (EMAAC). Total internal EMAAC unforced capacity of 30,825.1 MW includes all generating units and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. Including imports into EMAAC, RPM unforced capacity was 30,841.0 MW. Of the 2,121.8 MW of incremental supply, 2,092.4 MW cleared, which resulted in a resource-clearing price of $197.67 per MW-day.

  Total resources in EMAAC were 36,642.8 MW, which when combined with certified ILR of 387.0 MW resulted in a net excess of -206.9 MW (0.6 percent) less than the reliability requirement of 37,236.7 MW.

- Southwestern Mid-Atlantic Area Council (SWMAAC). Total internal SWMAAC unforced capacity of 10,352.2 MW includes all generating units and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. There were no imports from outside PJM into SWMAAC. All of the 650.1 MW of incremental supply cleared, resulting in a resource-clearing price of $188.54 per MW-day.

  Total resources in SWMAAC were 15,900.2 MW, which when combined with certified ILR of 273.4 MW resulted in a net excess of 98.3 MW (0.6 percent) greater than the reliability requirement of 16,075.3 MW.

Generator Performance

- Forced Outage Rates. From 2003 to 2004, the average PJM EFORd increased, from 6.7 percent in 2003 to 7.3 percent in 2004.[10] In 2005, the average PJM EFORd decreased to 6.6 percent, continued to decrease in 2006 to 6.4 percent and then increased to 6.9 percent in 2007. The increase in EFORd from 2006 to 2007 was the result of increased forced outage rates of combustion turbine and steam generating unit types. These forced outage rates are for the entire PJM Control Area.[11]

Conclusion

The RPM Capacity Market design was implemented effective June 1, 2007. RPM represents a significant change in the structure of the Capacity Market in PJM. The RPM is a forward-looking, annual, locational market, with a must-offer requirement for capacity and mandatory participation by load, with performance incentives for generation, that includes clear, market power mitigation rules and that permits the direct participation of demand-side resources.

The RPM Capacity Market design explicitly addresses the underlying issues of ensuring that competitive prices can reflect local scarcity while not relying on the exercise of market power to achieve the design objective and explicitly limiting the exercise of market power.

The Capacity Market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. This is the case for the CCM design as well as for the RPM. The demand for capacity includes expected peak load plus a reserve margin. Thus, the reliability goal is to have total supply equal to, or slightly above, the demand for capacity. The market may be long at times, but that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn adequate revenues in other markets, will retire. Demand is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The result is that any supplier that owns more capacity than the difference between total supply and the defined demand is pivotal and has market power.

In other words, the market design for capacity leads, almost unavoidably, to structural market power. Given the basic features of market structure in the PJM Capacity Market, including significant market structure issues, inelastic demand, tight supply-demand conditions, the relatively small number of nonaffiliated LSEs

10 Annual EFORd data presented in state of the market reports may be revised based on final data submitted after the publication of the reports.

11 In some cases, data for the AEP, DAY, DLCO, Dominion and ComEd control zones may be incomplete for the years 2002 and 2003. Only data that have been reported to PJM were used.

and supplier knowledge of aggregate market demand, the MMU concludes that the potential for the exercise of market power continues to be high. Market power is and will remain endemic to the existing structure of the PJM Capacity Market. This is not surprising in that the Capacity Market is the result of a regulatory/administrative decision to require a specified level of reliability and the related decision to require all load-serving entities to purchase a share of the capacity required to provide that reliability. It is important to keep these basic facts in mind when designing and evaluating capacity markets. The Capacity Market is unlikely ever to approach the economist's view of a competitive market structure in the absence of a substantial and unlikely structural change that results in much more diversity of ownership.

The RPM Capacity Market design represents a significant advance over the previous CCM design in ensuring competitive outcomes because RPM has explicit market power mitigation rules designed to permit competitive, locational capacity prices while limiting the exercise of market power. The RPM construct is consistent with the appropriate market design objectives of permitting competitive prices to reflect local scarcity conditions while explicitly limiting market power. The RPM Capacity Market design provides that competitive prices can reflect locational scarcity while not relying on the exercise of market power to achieve that design objective and limits the exercise of market power via the application of the three pivotal supplier test.

The introduction of the RPM design had a large impact on total capacity-related revenues. Under the CCM design, for calendar year 2006, capacity resources across the entire RTO were valued at a total of $299.0 million. Under the RPM, cleared capacity resources across the entire RTO, were valued at $4.3 billion under the 2007/2008 auction, an increase of approximately $4 billion.

The existence of a Capacity Market that links payments for capacity to the level of unforced capacity and therefore to the forced outage rate creates an incentive to improve forced outage rates. These incentives were somewhat attenuated in the CCM design. The performance incentives are stronger in the RPM Capacity Market design although they need further strengthening. The Energy Market also provides incentives for improved performance with somewhat different characteristics. Generators want to maximize their sales of energy when prices are high and if they are successful, this will also result in lower forced outage rates. Well-designed scarcity pricing could also provide strong, complementary incentives for reduced outages during high-load periods. It would be preferable to rely on strong market-based incentives for capacity resource performance rather than the current structure of penalties, which has its own incentive effects.

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis also examines participant behavior in the context of market structure. In a competitive market structure, market participants are constrained to behave competitively. In a competitive market structure, competitive behavior is profit-maximizing behavior. Finally, the analysis examines market performance results. The actual performance of the market, measured by price and the relationship between price and marginal cost, results from the interaction of these elements.

The MMU found serious market structure issues, but no exercise of market power in the PJM Capacity Market. The behavior of market participants in the context of the market structure and the supply and demand fundamentals offset these market structure issues in the PJM Capacity Market under the CCM construct in 2007. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive during 2007.

Capacity Credit Market

Market Design

The PJM CCM provided mechanisms to balance the supply of and demand for capacity unmet by the bilateral market or self-supply. The CCM consisted of the Daily, Interval, Monthly and Multimonthly CCM. The CCM was intended to provide a transparent, market-based mechanism for retail LSEs to acquire the capacity resources needed to meet their capacity obligations and to sell capacity resources when no longer needed to serve load. The Daily CCM permitted LSEs to match capacity resources with short-term shifts in retail load while the Interval, Monthly and Multimonthly CCMs provided mechanisms to match longer-term obligations to serve load with capacity resources.

Market Structure

The MMU analyzed the supply of and demand for capacity, market concentration in the PJM CCM and, for total capacity, internal and external bilateral capacity transactions and ALM activity.

Supply

System net excess capacity is a function of unforced capacity, capacity obligation, the sum of members' excesses and the sum of members' deficiencies. Unforced capacity includes capacity imports and exports. Net excess is the net pool position, calculated by subtracting total capacity obligation from total capacity resources. Since total capacity obligation includes expected total load plus a reserve margin, a pool net excess position of zero is consistent with established reliability objectives. Table 5-1 and Figure 5-1 present these data for January though May 2007.[12]

Under the CCM design, the capacity resources in PJM on any day reflected the addition of new resources, the retirement of old resources and the importing or exporting of capacity resources. These daily changes were a function of market forces. During January through May 2007, unforced capacity remained relatively constant in the PJM Capacity Market compared to 2006. Average unforced capacity increased by 377 MW from 152,482 MW to 152,859 MW, an increase of 0.2 percent. Capacity resources exceeded capacity obligations in PJM on every day and the daily average net excess was 9,450 MW (6.6 percent of average obligation), a decrease of 81 MW from the average net excess of 9,531 MW for 2006 (6.7 percent of average obligation).

12 These data were posted on a monthly basis at <http://www.pjm.com> under the PJM Market Monitoring Unit link.

Table 5-1 PJM capacity summary (MW): January through May 2007

	Mean	Standard Deviation	Minimum	Maximum
Installed capacity	162,401	332	161,994	162,841
Unforced capacity	152,859	221	152,468	153,149
Obligation	143,409	273	142,979	143,784
Sum of excess	9,450	408	8,931	10,170
Sum of deficiency	0	0	0	1
Net excess	9,450	408	8,930	10,170
Imports	2,794	20	2,785	2,839
Exports	4,939	221	4,621	5,302
Net exchange	(2,145)	225	(2,518)	(1,837)
Unit-specific transactions	15,495	216	15,358	15,961
Capacity credit transactions	147,514	2,694	144,134	152,028
Internal bilateral transactions	163,009	2,600	159,507	167,418
Daily capacity credits	3,458	189	3,057	3,893
Monthly capacity credits	2,252	362	1,860	2,881
Multimonthly capacity credits	6,017	364	5,375	6,325
All capacity credits	11,727	573	10,292	12,574
ALM credits	1,677	0	1,677	1,677

Figure 5-1 Capacity obligation for the PJM Capacity Market: January through May 2007

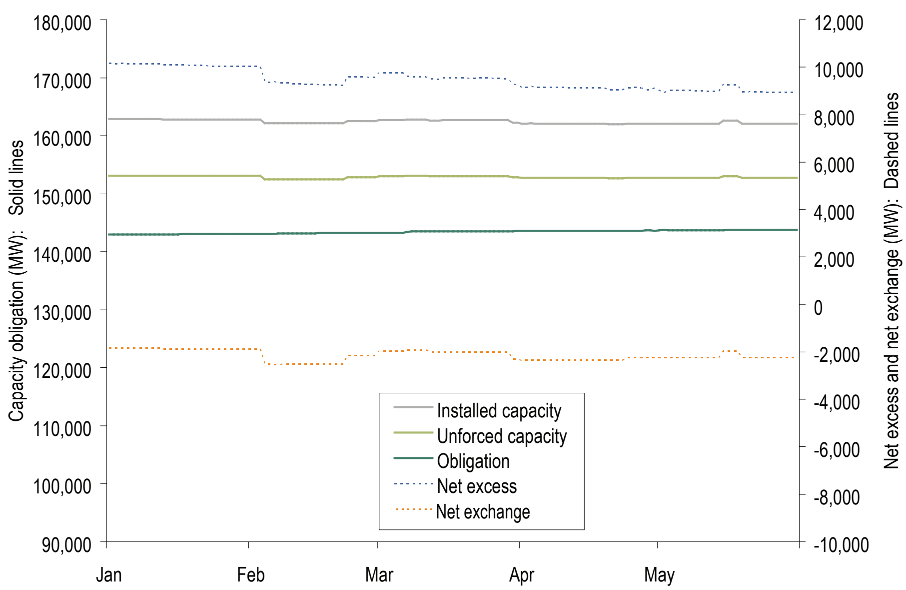
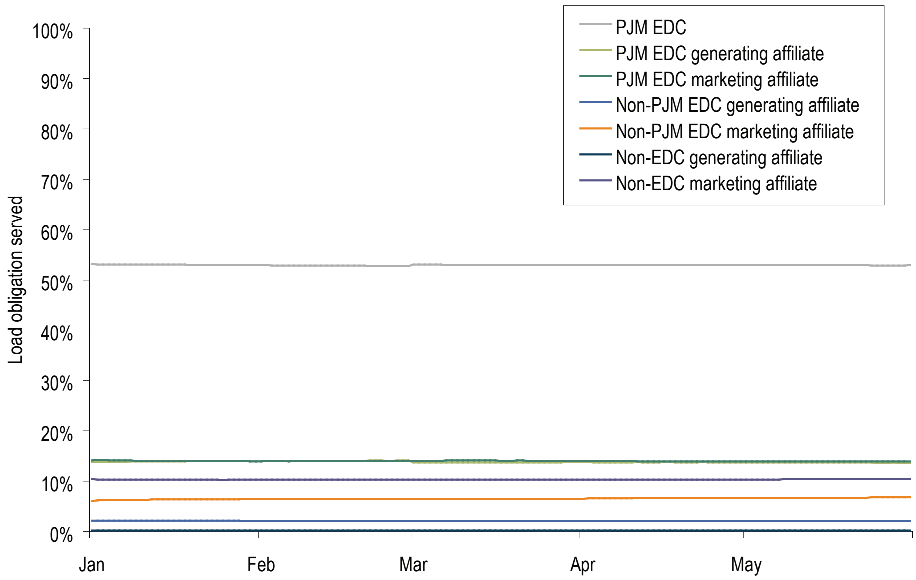


Figure 5-2 PJM Capacity Market load obligation served (Percent): January through May 2007



Demand

The total demand for capacity is the pool capacity obligation which is set annually via an administrative process. During January through May 2007, obligations remained relatively constant in the PJM Capacity Market compared to 2006. Average load obligations increased 458 MW or 0.3 percent from 142,951 MW to 143,409 MW.

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The Capacity Market was divided into the following sectors:

- PJM EDC. EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- PJM EDC Generating Affiliate. Affiliate companies of PJM EDCs that own generating resources.
- PJM EDC Marketing Affiliate. Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- Non-PJM EDC. EDCs with franchise service territories outside the PJM footprint.
- Non-PJM EDC Generating Affiliate. Affiliate companies of non-PJM EDCs that own generating resources.

- Non-PJM EDC Marketing Affiliate. Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.

- Non-EDC Generating Affiliate. Affiliate companies of non-EDCs that own generating resources.

- Non-EDC Marketing Affiliate. Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

During January through May 2007, PJM EDCs and their affiliates maintained a large market share of load obligations in the PJM Capacity Market, together averaging 80.8 percent (See Figure 5-2 and Table 5-2.), down from 87.6 percent for 2006. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates averaged 19.2 percent, up from 12.4 percent for 2006.

LSEs could meet their load obligations through self-supply, the PJM CCM or bilateral contracts with third parties.[13] As shown in Table 5-3, Table 5-4 and Table 5-5, reliance on these options varied by market sector.[14]

During January though May 2007, PJM EDCs self-supplied an average of 69.8 percent of their load obligations with their remaining obligations being supplied through bilateral contracts with third parties (32.1 percent) and the PJM CCM (0.4 percent). The self-supply percentage was up from the 2006 value of 56.7 percent, while the bilateral contract percentage decreased from 45.8 percent for 2006. In January through May 2007, entities in this sector, on average, purchased more capacity credits in the PJM CCM or through bilateral contracts with third parties than were required to meet their obligation, resulting in an average net excess of 1,785 MW (2.3 percent of obligation) as compared to a 2006 average net excess of 2,171 MW (2.4 percent of obligation) for this sector.

During January though May 2007, as in 2006, PJM EDC generating affiliates owned more capacity than their load obligations, were net capacity credit sellers both in the PJM CCM and through bilateral contracts and, except for non-PJM EDC generating affiliates, remained in higher net excess positions as a percentage of load obligations than the other sectors.

During January though May 2007, as in 2006, PJM EDC marketing affiliates were net capacity credit buyers in the PJM CCM and through bilateral contracts and bought more capacity credits than required to meet their obligation.

13 Self-supply is defined as the unforced MW of the units owned by an entity.

14 Negative values in the "Capacity Credit Market" and in the "Net Bilateral Contracts" columns mean that a sector sold more capacity credits than it purchased for the relevant time period. A positive number means that a sector purchased more capacity credits than it sold for the relevant time period.

Table 5-2 PJM Capacity Market load obligation served: January through May 2007

	Average Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Jan	75,799	19,955	20,116	3,048	9,095	303	14,719	143,035
Feb	75,614	20,150	20,046	3,007	9,308	305	14,746	143,176
Mar	75,999	19,749	20,190	3,014	9,375	306	14,830	143,463
Apr	75,985	19,783	20,094	3,011	9,550	307	14,887	143,617
May	76,041	19,709	20,030	3,009	9,677	308	14,968	143,742
Average	75,892	19,864	20,096	3,018	9,402	306	14,831	143,409
Percent of total obligation	52.9%	13.9%	14.0%	2.1%	6.6%	0.2%	10.3%	100.0%

Table 5-3 PJM Capacity Market load obligation served by PJM EDCs and affiliates: January through May 2007

	PJM EDCs					PJM EDC Generating Affiliates					PJM EDC Marketing Affiliates				
	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jan	53,150	952	23,936	75,799	2,239	64,233	(753)	(39,531)	19,955	3,994	0	1,557	19,036	20,116	477
Feb	52,889	366	23,966	75,614	1,607	64,233	(678)	(39,602)	20,150	3,803	0	1,606	18,792	20,046	352
Mar	52,790	382	24,559	75,999	1,732	63,570	(581)	(39,272)	19,749	3,968	0	1,701	18,734	20,190	245
Apr	52,804	252	24,571	75,985	1,642	63,443	(871)	(39,101)	19,783	3,688	0	1,719	18,721	20,094	346
May	53,188	(283)	24,822	76,041	1,686	63,016	95	(39,206)	19,709	4,196	0	1,484	18,906	20,030	360
Average	52,966	334	24,377	75,892	1,785	63,690	(553)	(39,339)	19,864	3,934	0	1,613	18,840	20,096	357
Percent of total obligation	69.8%	0.4%	32.1%		2.3%	320.6%	(2.8%)	(198.0%)		19.8%	0.0%	8.0%	93.7%		1.7%

Table 5-4 PJM Capacity Market load obligation served by non-PJM EDC affiliates: January through May 2007

	Non-PJM EDC Generating Affiliates					Non-PJM EDC Marketing Affiliates				
	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jan	12,601	(604)	(6,980)	3,048	1,969	0	1,622	7,716	9,095	243
Feb	12,601	(911)	(6,878)	3,007	1,805	0	2,073	7,532	9,308	297
Mar	12,715	(1,057)	(6,828)	3,014	1,816	0	2,143	7,514	9,375	282
Apr	12,715	(763)	(6,979)	3,011	1,962	0	2,183	7,575	9,550	208
May	12,715	(773)	(7,570)	3,009	1,363	0	2,347	7,574	9,677	244
Average	12,670	(820)	(7,051)	3,018	1,781	0	2,073	7,583	9,402	254
Percent of total obligation	419.8%	(27.2%)	(233.6%)		59.0%	0.0%	22.0%	80.7%		2.7%

Table 5-5 PJM Capacity Market load obligation served by non-EDC affiliates: January through May 2007

	Non-EDC Generating Affiliates					Non-EDC Marketing Affiliates				
	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jan	25,002	(1,669)	(22,187)	303	843	0	(1,106)	16,152	14,719	327
Feb	25,263	(1,950)	(22,056)	305	952	0	(505)	15,888	14,746	637
Mar	25,954	(1,910)	(22,562)	306	1,176	0	(678)	15,852	14,830	344
Apr	26,101	(2,094)	(22,831)	307	869	0	(427)	15,720	14,887	406
May	26,046	(2,196)	(22,738)	308	804	0	(673)	15,998	14,968	357
Average	25,679	(1,963)	(22,481)	306	929	0	(683)	15,924	14,831	410
Percent of total obligation	8,394.2%	(641.8%)	(7,348.9%)		303.5%	0.0%	(4.6%)	107.4%		2.8%

Market Concentration

Market concentration is assessed using market shares, concentration ratios and residual supply indices as measures. Concentration ratios are a summary measure of market share, a key element of market structure. The residual supply index (RSI) is a measure of the extent to which one or more generation owners are pivotal suppliers in a market.[15]

Capacity Credit Market

The pivotal supplier analysis indicates significant market structure issues in the Daily CCM and the Monthly and Multimonthly CCM for January through May 2007.[16] Table 5-6 shows RSI values for the daily CCM auctions and the monthly and multimonthly CCM auctions. The RSI results for the Daily CCM indicate that all daily auctions had three or fewer jointly pivotal suppliers. The average three pivotal supplier RSI level for January through May 2007 was 0.52, while one supplier was individually pivotal in 147 of the 151 daily auctions (97.4 percent). The RSI results for the Monthly and Multimonthly CCM indicate that all of the auctions had three or fewer jointly pivotal suppliers. The average three pivotal supplier RSI was 0.28, while one supplier was individually pivotal in 10 of the 12 monthly auctions (83.3 percent).

15 See the *2007 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1," for a more detailed discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI) and of the calculation of the residual supply index. See also the *2007 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test."

16 The RSI calculations use a market definition that includes those offers with offer prices less than, or equal to, 150 percent of the capacity market-clearing price for the relevant market. This is consistent with the appropriate definition of competitive offers.

Table 5-6 PJM CCM three pivotal supplier residual supply index (RSI): January through May 2007[17]

	Daily Market RSI_3	Monthly and Multimonthly Market RSI_3
Average	0.52	0.28
Minimum	0.43	0.00
Maximum	0.72	0.80
# Auctions	151	12
# Auctions with = 1 pivotal supplier	147	10
% Auctions with = 1 pivotal supplier	97.4%	83.3%
# Auctions with ≤ 3 pivotal suppliers	151	12
% Auctions with ≤ 3 pivotal suppliers	100.0%	100.0%

The HHI analysis indicates that, on average, the PJM CCM in January through May 2007 exhibited moderate levels of concentration in the Daily CCM and high levels of concentration in the Monthly and Multimonthly CCM.[18] As shown in Table 5-7, HHIs for the Daily CCM averaged 1291 during this period, with a maximum of 1552 and a minimum of 952 (four firms with equal market shares would result in an HHI of 2500).[19] The highest market share for any entity in one daily auction was 33.4 percent, while the highest average daily market share for any entity across all of the daily auctions was 21.6 percent.[20] HHIs for the longer-term Monthly and Multimonthly CCM averaged 2519, with a maximum of 5005 and a minimum of 1148. The highest market share for any entity in one monthly/multimonthly auction was 64.0 percent, while the highest average market share for any entity across all of the monthly/multimonthly auctions was 18.7 percent. All but one of the 12 monthly/multimonthly auctions (91.7 percent) had an HHI greater than 1800.

Table 5-7 PJM CCM HHI: January through May 2007

	Daily Market HHI	Monthly and Multimonthly Market HHI
Average	1291	2519
Minimum	952	1148
Maximum	1552	5005
Highest market share (one auction)	33.4%	64.0%
Highest market share (all auctions)	21.6%	18.7%
# Auctions	151	12
# Auctions with HHI >1800	0	11
% Auctions with HHI >1800	0.0%	91.7%

17 RSI_x is the residual supply index, using "x" pivotal suppliers.

18 The HHI calculations use capacity cleared in each respective auction.

19 PJM CCM results are reported by the time period during which the auction was run and not by the time period to which the auction applies.

20 The market share for an entity across all auctions is calculated as the average market share for the entity for all 151 daily auctions or all 12 monthly and multimonthly auctions. For auctions in which an entity did not participate or clear, the entity was assigned a zero market share in the calculation of the multi-auction market share.

Capacity Market – Total Capacity

The CCM market structure analyses include only the 8.2 percent of total PJM capacity obligations that were traded in the PJM CCM during the period from January through May 2007. To provide a more complete assessment of competition in the PJM Capacity Market, the MMU also analyzed total capacity without regard to whether it was sold in the PJM-operated CCM, through bilateral agreements or self-supplied.

The market structure in the aggregate PJM Capacity Market is shown for the beginning of the period (January 1) and the end of the period (May 31) in Table 5-8.

There was a single pivotal supplier throughout the period, with three individual suppliers who were each pivotal on a stand-alone basis. In other words, the capacity owned by any of these individually pivotal suppliers was required in order to meet the total demand for capacity (capacity obligation) in PJM. Total capacity ownership was at low concentration levels throughout the period, with HHI at 911 on January 1 and 895 on May 31.[21] The highest market share increased from 16.2 percent to 16.7 percent.

The market, as defined by total capacity, exhibits significant market structure issues, measured by the pivotal supplier results.[22] As a general matter, the results of the three pivotal supplier test can differ from the results of the HHI and market share tests, and total capacity illustrates that situation. As in this case, the three pivotal supplier test can show the existence of structural market power when the HHI is less than 2500, and the maximum market share is less than 20 percent. The three pivotal supplier test can also show the absence of market power when the HHI is greater than 2500, and the maximum market share is greater than 20 percent. The three pivotal supplier test is more accurate than the HHI and market share tests because it focuses on the relationship between demand and the ownership structure of supply available to meet it.

Table 5-8 PJM capacity: January through May 2007

	01-Jan	31-May
Unforced capacity (MW)	153,149	152,714
Obligation (MW)	142,979	143,780
Net excess (MW)	10,170	8,934
HHI	911	895
Highest market share	16.2%	16.7%
RSI_1	0.90	0.91
RSI_3	0.59	0.61
Pivotal suppliers	1	1

External and Internal Capacity Transactions

PJM capacity resources may be traded bilaterally within PJM and between PJM and external markets.

21 Under the CCM design, total capacity included all capacity in the PJM footprint, but was not a formal market and, therefore, there was no market-clearing price or quantity.
22 See the *2007 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test."

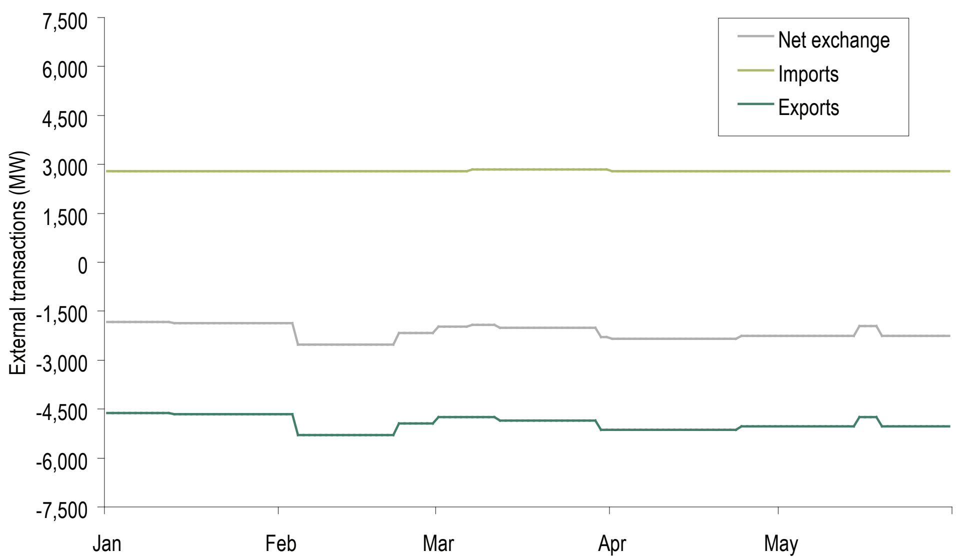
Imports and Exports

External bilateral transactions include imports of capacity resources from other control areas and exports of capacity resources to control areas outside of PJM.[23] Net exchange is equal to imports less exports.

As shown in Table 5-1 and Figure 5-3, Capacity Market participants' external bilateral purchases (imports) of capacity resources were relatively flat in January through May 2007, averaging 2,794 MW, a decrease of 299 MW or 9.7 percent from the average of 3,093 MW for 2006.

During January through May 2007, an average of 4,939 MW of capacity resources was exported from the PJM Capacity Market, a decrease of 19 MW or 0.4 percent from the average of 4,958 MW for 2006. The result was an average net exchange of -2,145 MW of capacity resources for January through May 2007, an increase of 280 MW or 15.0 percent from the average net exchange of -1,865 MW for 2006.

Figure 5-3 External PJM Capacity Market transactions: January through May 2007



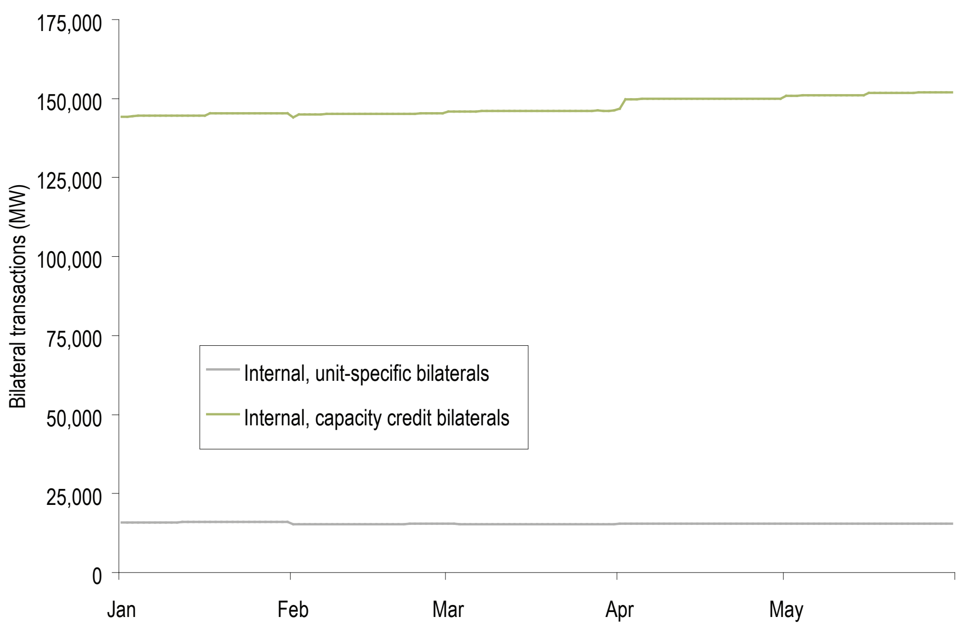
Internal Bilateral Transactions

Internal bilateral transactions are agreements between two parties to buy and sell capacity credits within PJM, but outside of the PJM Capacity Credit Market.[24] Unit-specific transactions are for capacity credits from a specific generating unit while capacity credit transactions are for non-unit-specific capacity credits. Both types of transactions may be repeated multiple times among parties, for the same units or credits, with the result that transaction volume can exceed obligation.

23 The sink (destination) of exports cannot be identified since these data are not required from member companies.
24 Through May 31, 2007, only volumes from internal bilateral transactions were reported to PJM. Pricing data were not required from member companies.

During January through May 2007, internal, unit-specific transactions for the PJM Capacity Market averaged 15,495 MW, which was a decrease of 53 MW or 0.3 percent from the average of 15,548 MW for 2006. (See Table 5-1 and Figure 5-4.) Internal capacity credit transactions during January through May 2007 averaged 147,514 MW, which was an increase of 2,110 MW or 1.5 percent from the average of 145,404 MW for 2006. Total internal bilateral transactions in January through May 2007 averaged 163,009 MW, an increase of 2,057 MW or 1.3 percent from the 160,952 MW average for 2006.

Figure 5-4 Internal bilateral PJM Capacity Market transactions: January through May 2007



ALM Credits

ALM reflects the ability of individual customers, under contract with their LSE, to reduce specified amounts of load during an emergency. ALM credits, measured in MW of curtailable load, reduce LSE capacity obligations and thus the total PJM capacity obligation.[25] The ALM construct was replaced when the CCM was replaced by RPM on June 1, 2007.

During January through May 2007, ALM credits in the PJM Capacity Market averaged 1,677 MW, down 151 MW (8.3 percent) from 1,828 MW in 2006. (See Table 5-1.)

25 ALM capacity credits reduce capacity obligations throughout the year. The fixed ALM value for non-summer months (October through May) is calculated by PJM based on daily values of nominated ALM in the PJM eCapacity system for the summer months.

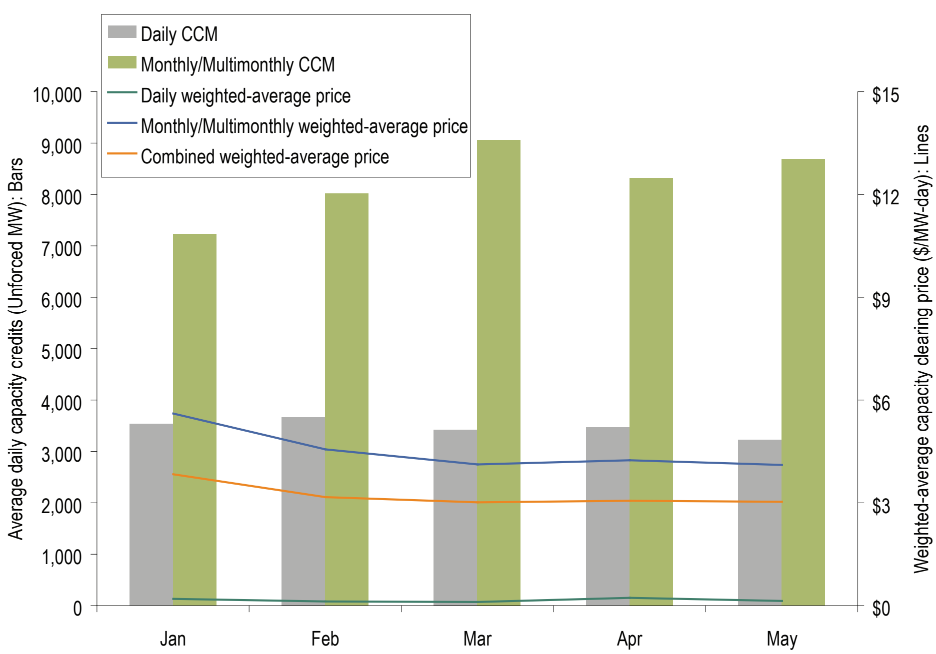
Market Performance

Capacity Credit Market Volumes and Prices

Figure 5-5 and Table 5-9 show prices and volumes in PJM's Daily, Monthly and Multimonthly CCM during January through May 2007. The Daily CCM averaged 3,458 MW of transactions, representing 2.4 percent of the period's 143,409 MW average daily capacity obligation. The average transaction volume for January through May 2007 was 445 MW greater than the 2006 average of 3,013 MW, which had been 2.1 percent of the 142,951 MW average capacity obligations for the period. The Monthly and Multimonthly CCM averaged 8,269 MW of transactions, which was 5.8 percent of the average daily capacity obligations for January through May 2007 and 2,164 MW higher than the 2006 average of 6,105 MW, which was 4.3 percent of the average capacity obligations for the period. Thus, on average, the CCM accounted for 8.2 percent of all average daily capacity obligations in January through May 2007.

The volume-weighted, average price for January through May 2007 was $0.16 per MW-day in the Daily CCM and $4.49 per MW-day in the Monthly and Multimonthly CCM. Prices in the Daily CCM during January through May 2007 were $1.76 lower than the 2006 price of $1.92. Prices in the Monthly and Multimonthly CCM were $3.11 lower than the 2006 price of $7.60. The volume-weighted, average price for the entire CCM was $3.21 per MW-day.[26] For calendar year 2006, capacity resources across the entire RTO were valued at a total of $299.0 million. This equals the total capacity obligation valued at the combined-market, weighted-average CCM clearing price for 2006.

Figure 5-5 PJM Daily and Monthly/Multimonthly CCM performance: January through May 2007



26 Graph and average price data are all in terms of unforced capacity. Capacity credits are, by definition, in terms of unforced capacity.

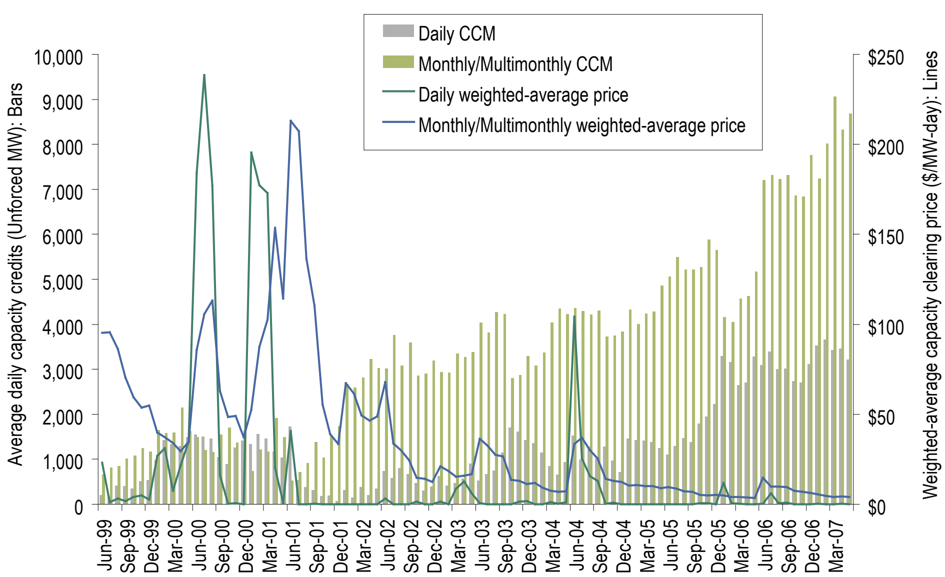
Table 5-9 PJM Capacity Credit Market: January through May 2007

	Average Daily Capacity Credits (MW)			Weighted-Average Price ($ per MW-day)		
	Daily CCM	Monthly and Multimonthly CCM	Combined Markets	Daily CCM	Monthly and Multimonthly CCM	Combined Markets
Jan	3,539	7,236	10,775	$0.19	$5.61	$3.83
Feb	3,664	8,015	11,679	$0.12	$4.56	$3.17
Mar	3,427	9,059	12,486	$0.10	$4.12	$3.02
Apr	3,464	8,325	11,789	$0.23	$4.24	$3.06
May	3,218	8,685	11,903	$0.14	$4.10	$3.03
Average	3,458	8,269	11,727	$0.16	$4.49	$3.21

June 1999 through May 2007

Figure 5-6 and Table 5-10 show prices and volumes in PJM's Daily and longer-term CCM from June 1999 through May 2007.[27] After a series of rule changes including the interval system were introduced in July 2001, overall volume in the CCM increased. After the rule changes, prices declined across the period with the exception of the summers of 2004 and 2006 and the first few days of January 2006. The share of load obligation traded in both the Daily CCM and in the Monthly and Multimonthly CCM remained relatively stable after 2001.

Figure 5-6 PJM Daily and Monthly/Multimonthly CCM performance: June 1999 through May 2007



27 After June 1, 1999, the PJM Capacity Credit Market was based on unforced capacity. Prior to this date, the market had been based on installed capacity.

Table 5-10 PJM Capacity Credit Market: June 1999 to May 2007

	Average Daily Capacity Credits						Weighted-Average Price ($ per MW-day)		
	Daily CCM (MW)	Percent of Obligation	Monthly and Multimonthly CCM (MW)	Percent of Obligation	Combined Markets (MW)	Percent of Obligation	Daily CCM	Monthly and Multimonthly CCM	Combined Markets
1999	374	0.7%	981	1.9%	1,355	2.6%	$4.69	$70.36	$52.24
2000	1,304	2.5%	1,561	3.0%	2,865	5.4%	$69.39	$53.16	$60.55
2001	829	1.5%	1,197	2.2%	2,026	3.7%	$87.98	$100.43	$95.34
2002	450	0.8%	3,066	5.3%	3,516	6.1%	$0.59	$38.21	$33.40
2003	907	1.4%	3,436	5.2%	4,343	6.6%	$2.14	$21.57	$17.51
2004	1,062	1.4%	3,966	5.1%	5,028	6.5%	$17.21	$17.88	$17.74
2005	1,516	1.2%	4,968	3.9%	6,484	5.1%	$0.15	$7.94	$6.12
2006	3,013	2.1%	6,105	4.3%	9,118	6.4%	$1.92	$7.60	$5.73
2007	3,458	2.4%	8,269	5.8%	11,727	8.2%	$0.16	$4.49	$3.21

RPM Capacity Market

Market Design

On June 1, 2007, the RPM Capacity Market design was implemented in the PJM region, replacing the CCM Capacity Market design that had been in place since 1999.[28] The RPM market design differs from the CCM market design in a number of important ways. The RPM is a forward-looking, annual, locational market with a must-offer requirement for capacity and mandatory participation by load that includes clear, market power mitigation rules and that permits the direct participation of demand-side resources. CCM, in contrast, was a daily, single-price, voluntary balancing market that included less than 10 percent of total PJM capacity, that had no explicit market power mitigation rules and that did permit the participation of demand-side resources. Under RPM, capacity obligations are annual. Under CCM, capacity obligations were daily. Under RPM, auctions are held for delivery years that are three years in the future. Under CCM daily, monthly and multimonthly auctions were held. Under RPM, prices are locational and may vary depending on transmission constraints.[29] Under CCM, prices were the same, regardless of location. Under RPM, sell offers are unit-specific. Under CCM, offers were non-unit-specific capacity credits. Under RPM, existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for the FRR option. Under CCM, there was no must-offer rule after June 2000. Under RPM, participation by LSEs is mandatory, except for the FRR option. Under CCM, there was no mandatory participation in the CCM auctions.[30] Under RPM there is an administratively determined demand curve that, with the supply curve derived from capacity offers, determines market prices. Under CCM the demand was defined by participant buy bids. Under RPM there are explicit market power mitigation rules that define structural market power, that define offer caps based on the marginal cost of capacity and that do not limit prices offered by new entrants. Under CCM,

28 For additional information on the RPM, see PJM. "Manual 18: PJM Capacity Market," Revision 2 (Effective February 21, 2008), p. 11 <http://www.pjm.com/contributions/pjm-manuals/pdf/m18.pdf> (604 KB).

29 Transmission constraints are local capacity import capability limitations (low CETL margin over CETO) caused by transmission facility limitations, voltage limitations or stability limitations.

30 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Schedule 8.1 (June 1, 2007) (Accessed July 19, 2007) <http://www.pjm.com/documents/downloads/agreements/raa.pdf> (1.92 MB).

there were no explicit market power mitigation rules. Under RPM, demand-side resources may be offered directly into the auctions and receive the clearing price. Under CCM, demand-side resources could not be offered directly into the market.

The first four base RPM Auctions comprise the RPM transition period.[31] Three base RPM Auctions were held during 2007 in April, July and October for the delivery years 2007/2008, 2008/2009 and 2009/2010, respectively.[32] A fourth transition period auction was held in January 2008 for the delivery year 2010/2011. After this transition period, annual base auctions will be held in May for delivery years that are three years in the future. First, second and third incremental RPM Auctions may be held for each delivery year, occurring 23, 13 and four months, respectively, prior to the delivery year. The first incremental auction to be held by PJM was the third incremental auction for 2008/2009, held in January 2008.[33]

Market Structure

Supply

As shown in Table 5-11, total internal capacity increased from 154,985.5 MW on January 1, 2007, to 155,206.0 MW on June 1, 2007, or 220.5 MW.[34] This increase was the result of 573.2 MW from DR offered into the auction, offset in part by 332.6 MW from higher EFORds and 20.1 MW from generation deratings. No new generation was offered into the 2007/2008 RPM Auction.

In the 2008/2009 and 2009/2010 auctions, new generation increased 528.6 MW; 112.6 MW were brought out of retirement and net generation uprates were 220.3 MW, for a total of 861.5 MW. DR offers increased 815.9 MW through June 1, 2009. Net improvements in EFORds added 434.8 MW. The net effect from May 31, 2007, through June 1, 2009, was an increase in total internal capacity of 2,350.6 MW (1.5 percent) from 154,967.6 MW to 157,318.2 MW.

As shown in Table 5-11 and Table 5-17, in the 2008/2009 RPM Auction, the increase of 15 units included five new wind units (66.1 MW), three new diesel units (23.3 MW) and two units (112.6 MW) which came out of retirement while the remaining five units were the result of a reclassification of external units.[35] There were 23 DR resources offered compared to 15 DR resources offered in the 2007/2008 RPM Auction.[36]

As also shown in Table 5-11 and Table 5-17, in the 2009/2010 RPM Auction, the increase of 17 units included eight new CT units (380.2 MW), two new diesel units (9.2 MW) and one new steam unit (49.8 MW) while the remaining increase of six units was the result of a combination of more units imported, less units exported, a decrease in units excused from offering into the auction and fewer units removed from the auction under the FRR option. There were 38 DR resources offered compared to 23 DR resources offered in the 2008/2009 RPM Auction.

31 For more detailed analysis of the 2007/2008, 2008/2009 and 2009/2010 RPM Auctions, see: "Analysis of the 2007-2008 RPM Auction" (August 16, 2007); "Analysis of the 2008-2009 RPM Auction" (November 30, 2007); "Analysis of the 2009-2010 RPM Auction" (November 30, 2007) < http://www.pjm.com/markets/market-monitor/reports.html.>

32 Delivery years are from June 1 through May 31. The 2007/2008 delivery year runs from June 1, 2007, through May 31, 2008.

33 More detailed analyses of individual RPM Auctions have been developed by the PJM Market Monitoring Unit and are posted on the Web site at < http://www.pjm.com/markets/market-monitor/reports.html.>

34 Unless otherwise specified, all volumes and prices are in terms of UCAP, which is calculated as installed capacity (ICAP) times (1-EFORd). The EFORd values here are the EFORd values used in the RPM Auctions.

35 Certain external hydroelectric units were allocated from the LDA level to the zonal level, resulting in an increased unit count.

36 Some generation and DR resources had multiple associated offers.

Table 5-11 Internal capacity: January 1, 2007, through June 1, 2009[37]

	UCAP (MW)			
	RTO	EMAAC	SWMAAC	MAAC+APS
Total internal capacity @ 01-Jan-07	154,985.5			
Generation capmods	(17.9)			
Total internal capacity @ 31-May-07	154,967.6	30,845.7	10,441.5	
New generation	0.0	0.0	0.0	
Units out of retirement	0.0	0.0	0.0	
Generation capmods	(2.2)	(65.3)	(109.0)	
DR mods	573.2	44.7	19.7	
Net EFORd effect	(332.6)	0.0	0.0	
Total internal capacity @ 01-Jun-07	155,206.0	30,825.1	10,352.2	
New generation	89.4	0.0	0.0	
Units out of retirement	112.6	112.6	0.0	
Generation capmods	146.2	105.9	38.9	
DR mods	595.3	298.7	294.3	
Net EFORd effect	818.5	36.8	91.7	
Total internal capacity @ 01-Jun-08	156,968.0	31,379.1	10,777.1	72,889.5
New generation	439.2		0.0	109.9
Units out of retirement	0.0		0.0	0.0
Generation capmods	74.1		(298.2)	(149.7)
DR mods	220.6		42.3	163.2
Net EFORd effect	(383.7)		(176.0)	0.0
Total internal capacity @ 01-Jun-09	157,318.2		10,345.2	73,012.9

Demand

There was a 5,298.6 MW increase in the RPM reliability requirement, which is similar to the obligation under CCM, from 142,978.7 MW on January 1, 2007, to 148,277.3 MW on June 1, 2007. This increase resulted from a higher peak-load forecast starting June 1.

On June 1, 2007, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 77.5 percent (Table 5-12), down from an average of 80.8 percent for the first five months of 2007 under CCM. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 22.5 percent, up from an average of 19.2 percent for the first five months of 2007 under CCM. Obligation is defined as cleared MW plus ILR forecast obligations.

37 The RTO includes MAAC+APS, EMAAC and SWMAAC. MAAC+APS includes EMAAC and SWMAAC. In the 2009/2010 RPM Auction, EMAAC was not constrained, so results for it are not shown. Maps of the LDAs can be found in the *2007 State of the Market Report*, Appendix A, "PJM Geography."

Table 5-12 PJM Capacity Market load obligation served: June 1, 2007

	Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Obligation	58,455.6	21,006.3	22,132.6	948.8	10,623.8	222.3	17,680.3	131,069.7
Percent of total obligation	44.6%	16.0%	16.9%	0.7%	8.1%	0.2%	13.5%	100.0%

Market Concentration

Preliminary Market Structure Screen

Under the terms of the PJM Tariff, the MMU is required to apply the PMSS prior to RPM auctions.[38] The purpose of the PMSS is to determine whether additional data are needed from owners of capacity resources in the defined areas in order to permit the MMU to apply the market structure tests defined in the Tariff.

An LDA or the RTO Region fails the PMSS if any one of the following three screens is failed: the market share of any capacity resource owner exceeds 20 percent; the HHI for all capacity resource owners is 1800 or higher; or there are not more than three jointly pivotal suppliers.[39]

As shown in Table 5-13, all defined markets failed the PMSS. As a result, capacity resource owners were required to submit avoidable cost rate (ACR) data to the MMU for resources for which they intended to submit nonzero sell offers unless certain other conditions were met.[40]

38 See PJM. “Open Access Transmission Tariff (OATT),” “Attachment DD: Reliability Pricing Model,” Original Sheet No. 605 (Effective June 1, 2007), section 6.3 (a) i.

39 See PJM. “Open Access Transmission Tariff (OATT),” “Attachment DD: Reliability Pricing Model,” Original Sheet No. 605 (Effective June 1, 2007), section 6.3 (a) ii.

40 See PJM. “Open Access Transmission Tariff (OATT),” “Attachment DD: Reliability Pricing Model,” First Revised Sheet No. 610 (Effective June 20, 2007), section 6.7 (c).

Table 5-13 Preliminary market structure screen results: 2007/2008 through 2009/2010 RPM Auctions

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
2007/2008				
RTO	16.0%	895	1	Fail
EMAAC	32.0%	2155	1	Fail
SWMAAC	49.8%	4259	1	Fail
2008/2009				
RTO	18.5%	879	1	Fail
EMAAC	33.1%	2180	1	Fail
SWMAAC	47.5%	4290	1	Fail
2009/2010				
RTO	18.4%	853	1	Fail
SWMAAC	51.1%	4229	1	Fail
MAAC+APS	26.9%	1627	1	Fail

Auction Market Structure

As shown in Table 5-14, all participants in the total PJM market as well as the LDA RPM markets failed the TPS test in each auction.[41] The result was that offer caps were applied to all sell offers. The RTO market includes all supply which cleared at or below the unconstrained clearing price. The LDA markets include the incremental supply in the LDAs which was required to meet the demand for capacity in each LDA and which cleared at a price higher than the unconstrained price.

41 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. The appropriate market definition to use for the one pivotal supplier test includes all offers with costs less than, or equal to, 1.05 times the clearing price. See the *2007 State of the Market Report*, Appendix L, "Three Pivotal Supplier Test" for additional discussion.

Table 5-14 RSI results: 2007/2008 through 2009/2010 RPM Auctions

RPM Markets	$RSI_{1\ 1.05}$	RSI_3
2007/2008		
RTO	0.82	0.59
EMAAC	0.12	0.01
SWMAAC	0.06	0.00
2008/2009		
RTO	0.82	0.61
EMAAC	1.10	0.25
SWMAAC	0.32	0.00
2009/2010		
RTO	0.82	0.60
MAAC+APS	0.83	0.37
SWMAAC	0.57	0.00

Imports and Exports

As shown in Table 5-15, net exchange decreased 707.6 MW from January 1 to June 1. Net exchange, which is imports less exports, increased due to a decrease in exports of 682.9 MW and an increase in imports of 24.7 MW.

Table 5-15 PJM capacity summary (MW): January 1, 2007, through June 1, 2009

		1-Jan-07	31-May-07	01-Jun-07	01-Jun-08	01-Jun-09
Installed capacity (ICAP)		162,840.7	162,036.6	163,721.1	164,444.1	166,916.0
Unforced capacity (pre-RPM)	A	153,148.6	152,714.3	154,076.7	155,590.2	157,628.7
Cleared capacity	B			129,409.2	129,597.6	132,231.8
Obligation/RPM reliability requirement (pre-FRR)	C	142,978.7	143,780.2	148,277.3	150,934.6	153,480.1
Obligation/RPM reliability requirement (less FRR)	D			125,805.0	128,194.6	130,447.8
Net excess (pre-RPM)	A-C	10,169.9	8,934.1	5,799.4	4,655.6	4,148.6
Net excess (RPM)	B-D+E-F			5,240.5	3,066.6	3,445.7
Imports		2,784.5	2,784.6	2,809.2	2,460.3	2,505.4
Exports		(4,621.4)	(5,038.0)	(3,938.5)	(3,838.1)	(2,194.9)
Net exchange		(1,836.9)	(2,253.4)	(1,129.3)	(1,377.8)	310.5
ALM		1,676.7	1,676.7			
DR cleared				127.6	536.2	892.9
ILR	E			1,636.3	2,109.9	2,107.5
FRR DR	F				446.3	445.8
HHI		911	895	895	879	853
Highest market share		16.2%	16.7%	16.0%	18.5%	18.4%
RSI_3		0.59	0.61	0.59	0.61	0.60
Pivotal suppliers		1	1	1	1	1

Demand-Side Resources

As part of the RPM redesign of the Capacity Market, the PJM ALM program was replaced by the PJM load management (LM) program. Under ALM, providers had received a MW credit which offset their capacity obligation. With the introduction of LM, qualifying load management resources can be offered into RPM Auctions as capacity resources and receive the clearing price, or they can be offered outside of the auction and receive the final, zonal ILR price.

The LM program introduced two RPM-related products. DR resources are load resources that are offered into an RPM Auction as capacity and receive the relevant LDA or RTO resource-clearing price. ILR resources are load resource that are not offered into the RPM Auction, but receive the final, zonal ILR price determined after the close of the second incremental auction.

Under the ALM program, resources could be nominated at any time prior to the day that ALM was called upon by PJM. Under RPM, DR resources must be offered into the auction for the delivery year during which they will participate while ILR resources must be certified by a published deadline which is after the base auction for the delivery year but at least three months prior to the delivery year during which they will participate.

As shown in Table 5-16, capacity in the RPM load management programs, which is a combination of DR cleared in the RPM Auctions and certified/forecast ILR, increased from the 1,676.7 MW in the CCM ALM program by 87.2 MW on June 1, 2007, by an additional 882.2 MW on June 1, 2008, and an additional 354.3 MW on June 1, 2009. Final ILR will be certified three months before the delivery year and it may differ from the ILR forecast.

Table 5-16 Load management statistics: May 31, 2007, through June 1, 2009

	UCAP (MW)			
	RTO	EMAAC	SWMAAC	MAAC+APS
DR cleared	127.6	44.7	19.7	
ILR certified	1,636.3	387.0	273.4	
Total load management @ 01-June-2007	1,763.9	431.7	293.1	
DR cleared	536.2	168.7	309.2	
ILR forecast	2,109.9	396.1	346.2	
Total load management @ 01-June-2008	2,646.1	564.8	655.4	
DR cleared	892.9		356.3	813.9
ILR forecast	2,107.5		345.7	1,055.7
Total load management @ 01-June-2009	3,000.4		702.0	1,869.6
ALM @ 31-May-2007	1,676.7			

Market Conduct

Offer Caps

If a capacity resource owner failed the market power test for the auction, avoidable costs were used to calculate offer caps for that owner's resources. Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year.[42] In effect, avoidable costs are the costs that a generation owner would not incur if the generating unit were mothballed for the year. In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs also include annual capital recovery associated with investments required to maintain a unit as a capacity resource. This component of avoidable costs is termed the avoidable project investment recovery rate (APIR). Avoidable costs are the defined costs less net revenues from all other PJM markets and from unit-specific bilateral contracts. The specific components of avoidable costs are defined in the PJM Tariff.

Capacity resource owners could provide ACR data by providing their own unit-specific data, by selecting the default ACR values calculated by the MMU, by submitting an opportunity cost for a possible export, by inputting a transition adder or by using combinations of these options. The opportunity cost option for exports allows resource owners to input a documented export price as the opportunity cost offer for the unit. If the relevant RPM market clears above the opportunity cost, the unit's capacity is sold in the RPM market. If the opportunity cost is greater than the clearing price, the unit's capacity does not clear in the RPM market and it is available for export. The transition adder was added to the offer cap, if appropriate, regardless of the offer-cap calculation method.[43]

2007/2008 RPM Auction

As shown in Table 5-17, of the 1,061 generating units which submitted offers, unit-specific offer caps were calculated for 125 units (11.8 percent). Offer caps of all kinds were used by 566 units (53.4 percent), of which 388 were the default (proxy) offer caps calculated and posted by the MMU. Of the 1,061 generating units, the remaining 495 units were price takers, of which the offers for 492 units were zero and the offers for three units were set to zero because no data were submitted. The transition adder was part of 263 offers, of which 50 offers included only the transition adder. The transition adder had no impact on the clearing prices. Fifteen DR resources offered into the auction.

Of the 1,061 generating units which submitted offers, 69 (6.5 percent) included an APIR component. (See Table 5-17.) As shown in Table 5-18, of the $79.34 per MW-day of ACR, the APIR component added $18.50 per MW-day to the ACR value of these 69 units in 2007/2008.[44] The default ACR values include an average APIR of $0.91 per MW-day. As the APIR component increased over the next two auctions to $195.85 per MW-day in 2009/2010, offer caps correspondingly increased as well from a weighted-average

42 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," Original Sheet No. 617 (Effective June 1, 2007), section 6.8 (b).

43 The transition adder, which is added to the calculated offer cap, is $10.00 per MW-day for delivery years 2007/2008 and 2008/2009 and $7.50 per MW-day for delivery year 2009/2010. It can be applied only up to 3,000 MW of unforced capacity per owner, only in unconstrained markets and only by those parent companies which own no more than 10,000 MW of unforced capacity in PJM.

44 The 69 units which had an APIR component submitted $141.3 million for capital projects on 7,681.1 MW UCAP.

of $16.99 per MW-day in 2007/2008 to $55.74 per MW-day in 2009/2010. The highest APIR was for subcritical/supercritical coal units. The maximum APIR effect ($133.86 per MW-day in 2007/2008) is the maximum amount by which an offer cap was increased by APIR.

Table 5-17 ACR statistics: 2007/2008 through 2009/2010 RPM Auctions[45]

	2007/2008		2008/2009		2009/2010	
Calculation Type	Number of Units	Percent of Generating Units Offered	Number of Units	Percent of Generating Units Offered	Number of Units	Percent of Generating Units Offered
Default ACR selected	388	36.6%	399	37.1%	377	34.5%
ACR data input (non-APIR)	56	5.3%	37	3.4%	22	2.0%
ACR data input (APIR)	69	6.5%	80	7.4%	129	11.8%
Opportunity cost input	3	0.3%	8	0.7%	10	0.9%
Transition adder only	50	4.7%	43	4.0%	12	1.1%
Offer caps calculated	566	53.4%	567	52.6%	550	50.3%
Uncapped new units	0	0.0%	0	0.0%	3	0.3%
Generator price takers	495	46.6%	509	47.4%	540	49.4%
Generating units offered	1,061	100.0%	1,076	100.0%	1,093	100.0%
Demand resources offered	15		23		38	
Total capacity resources offered	1,076		1,099		1,131	

45 This table has been updated since the report on the 2007/2008 RPM Auction was posted.

Table 5-18 APIR statistics: 2007/2008 through 2009/2010 RPM Auctions[46, 47]

	Weighted-Average ($ per MW-day UCAP)					
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	SubCritical/ SuperCritical Coal	Other	Total
2007/2008						
ACR	$37.93	$24.25	$76.55	$157.69	$31.43	$79.34
Net revenues	$69.09	$23.03	$22.65	$330.84	$142.88	$148.63
Offer caps	$12.86	$11.30	$59.01	$12.70	$10.66	$16.99
APIR	$0.69	$10.73	$17.54	$44.87	$0.00	$18.50
Maximum APIR effect						$133.86
2008/2009						
ACR	$37.65	$23.87	$88.09	$170.64	$50.14	$93.34
Net revenues	$63.51	$20.93	$23.72	$339.52	$271.26	$169.83
Offer caps	$14.57	$12.40	$64.90	$22.34	$13.07	$21.93
APIR	$0.80	$4.92	$28.47	$131.38	$15.54	$49.29
Maximum APIR effect						$211.28
2009/2010						
ACR	$40.99	$29.78	$106.57	$278.10	$57.60	$146.22
Net revenues	$69.54	$21.68	$25.39	$332.89	$269.63	$178.73
Offer caps	$17.37	$17.06	$105.75	$74.18	$34.48	$55.74
APIR	$0.24	$22.86	$43.79	$386.13	$18.96	$195.85
Maximum APIR effect						$383.79

2008/2009 RPM Auction

As shown in Table 5-17, 1,076 generating units submitted offers into the 2008/2009 RPM Auction as compared to the 1,061 generating units offered in the 2007/2008 RPM Auction. Unit-specific offer caps were calculated for 117 units (10.8 percent). Offer caps of all kinds were used by 567 units (52.6 percent), of which 399 were the default (proxy) offer caps calculated and posted by the MMU. Of the 1,076 generating units, the remaining 509 units were price takers, of which the offers for 472 units were zero and the offers for 37 units were set to zero because no data were submitted. The transition adder was part of the offers on 255 units, of which offers on 43 units included only the transition adder. The transition adder had no impact on the clearing prices.

Of the 1,076 generating units which submitted offers, 80 (7.4 percent) included an APIR component. (See Table 5-17.) As shown in Table 5-18, of the $93.34 per MW-day of ACR, the APIR component added

46 The weighted-average offer cap can still be positive even when the weighted-average net revenues are higher than the weighted-average ACR due to the offer-cap minimum being zero. On a unit basis, if net revenues are greater than ACR, net revenues in an amount equal to the ACR are used in the calculation and the offer cap is zero.

47 The weighted-average APIR is only for those units which had an APIR component, while the weighted-average values for ACR, net revenues and offer caps are for all units which submitted ACR data.

$49.29 per MW-day to the ACR value of these 80 units in 2008/2009.[48] The default ACR values include an average APIR of $0.91 per MW-day. The maximum APIR effect ($211.28 per MW-day) is the maximum amount by which an offer cap was increased by APIR. This value is less than the maximum APIR ($283.09 per MW-day) because of the net revenue offset to ACR plus APIR.

2009/2010 RPM Auction

As shown in Table 5-17, 1,093 generating units submitted offers in the 2009/2010 RPM Auction as compared to 1,076 generating units offered in the 2008/2009 RPM Auction. Unit-specific offer caps were calculated for 151 units (13.8 percent). Offer caps of all kinds were used by 550 units (50.3 percent), of which 377 were the default (proxy) offer caps calculated and posted by the MMU. Of the 1,093 generating units, three new units had uncapped offers while the remaining 540 units were price takers, of which the offers for 514 units were zero and the offers for 26 units were set to zero because no data were submitted.[49] The transition adder was part of the offers on 206 units, of which offers on 12 units included only the transition adder. The transition adder had no impact on the clearing prices.

Of the 1,093 generating units which submitted offers, 129 (11.8 percent) included an APIR component. (See Table 5-17.) As shown in Table 5-18, of the $146.22 per MW-day of ACR, the APIR component added $195.85 per MW-day to the ACR value of these 129 units in 2009/2010.[50] The default ACR values include an average APIR of $0.91 per MW-day. The maximum APIR effect ($383.79 per MW-day) is the maximum amount by which an offer cap was increased by APIR. This value is less than the maximum APIR ($808.36 per MW-day) because of the net revenue offset to ACR plus APIR.

Market Performance

Prices for capacity increased from a CCM combined-market, weighted-average price of $3.21 per MW-day for the entire RTO for the first five months of 2007 to a 2007/2008 high of $197.67 per MW-day (EMAAC), a 2008/2009 high of $210.11 per MW-day (SWMAAC) and a 2009/2010 high of $237.33 per MW-day (SWMAAC). The combined CCM/RPM 2007 weighted-average price was $88.09 per MW-day. (See Table 5-19.)

As Table 5-15 shows, net excess as calculated under CCM decreased 6,021.3 MW from 10,169.9 MW on January 1, 2007, to 4,148.6 MW on June 1, 2009, because of a 10,501.4 MW increase in the RPM reliability requirement, which is similar to the obligation under CCM, from 142,978.7 MW to 153,480.1 MW.[51] This increase was caused by a higher peak-load forecast and was partially offset by an increase of 4,480.1 MW in unforced capacity (pre-RPM) from 153,148.6 MW on January 1, 2007, to 157,628.7 MW on June 1, 2009.[52] The increase in unforced capacity was the result of a decrease in exports of 2,426.5 MW plus a 2,332.7 MW growth in total internal capacity (Table 5-11), both of which were partially offset by a decrease

48 Of the 80 units which had an APIR component, 77 units had current year capital dollars submitted of $421.1 million on 7,234.9 MW UCAP. Three units had APIR based only on the inclusion of 2007/2008 capital projects.

49 Generally, planned units are not subject to mitigation. The seven other planned units submitted zero price offers. See PJM. “Open Access Transmission Tariff (OATT),” “Attachment DD: Reliability Pricing Model,” Original Sheet No. 617 (Effective June 1, 2007), section 6.5 (a) ii.

50 Of the 129 units which had an APIR component, 109 units had current year capital dollars submitted of $2.5 billion on 14,519.2 MW UCAP. Twenty units had APIR based only on the inclusion of 2007/2008 and 2008/2009 capital projects.

51 Net excess under CCM was calculated as unforced capacity less obligation.

52 Unforced capacity (pre-RPM) is defined as the UCAP value of iron in the ground plus the UCAP value of imports less the UCAP value of exports.

in imports of 279.1 MW. On June 1, 2009, net excess as calculated under RPM (3,445.7 MW) was 702.9 MW less than the 4,148.6 MW as calculated under CCM.[53]

Table 5-19 Capacity prices: January 1, 2007, through May 31, 2010

	CCM Combined Markets Weighted-Average Price ($ per MW-day)	RPM Clearing Price ($ per MW-day)			
		RTO	EMAAC	SWMAAC	MAAC+APS
Jan	$3.83				
Feb	$3.17				
Mar	$3.02				
Apr	$3.06				
May	$3.03				
Jun 07 - May 08		$40.80	$197.67	$188.54	
Jun 08 - May 09		$111.92	$148.80	$210.11	
Jun 09 - May 10		$102.04		$237.33	$191.32
Average	$3.21				
2007 weighted-average CCM/RPM	$88.09				

2007/2008 RPM Auction

Cleared capacity resources across the entire RTO, accounting for LDA prices and volumes, will receive a total of $4.3 billion.

RTO

Table 5-20 shows total RTO offer data for the 2007/2008 RPM Auction, which includes the EMAAC and SWMAAC LDAs. Total internal RTO unforced capacity of 155,206.0 MW includes all generating units and DR that qualified as a PJM capacity resource for the 2007/2008 RPM Auction, excluding external units, and also includes owners' modifications to installed capacity ratings which are permitted under the PJM Reliability Assurance Agreement (RAA) and associated manuals.[54]

After accounting for FRR committed resources and for imports, RPM capacity was 135,092.6 MW.[55] This amount was reduced by exports of 3,938.5 MW[56] and 270.3 MW which were excused from the RPM must-offer requirement as a result of environmental regulations (151.0 MW), generation moving behind the meter (13.3 MW), non-utility generator (NUG) ownership questions (18.4 MW), expected unit retirements (79.8 MW) and other factors (7.8 MW). Subtracting 35.8 MW of FRR optional volumes not offered, resulted in

53 Net excess under RPM is calculated as cleared capacity less the reliability requirement plus ILR. For 2007/2008, certified ILR is used. For 2008/2009 and 2009/2010, forecast ILR less FRR DR is used in the calculation.

54 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region" (June 1, 2007) (Accessed July 19, 2007) <http://www.pjm.com/documents/downloads/agreements/raa.pdf> (1.92 MB).

55 The FRR alternative allows an LSE, subject to certain conditions, to avoid direct participation in the RPM Auctions. The LSE is required to submit an FRR capacity plan to satisfy the unforced capacity obligation for all load in its service area.

56 If all of the exports had been offered into the auction at $0.00 per MW-day, the clearing price would have been approximately $12.00 per MW-day.

130,848.0 MW that were available to be offered into the auction.[57] Offered volumes included 811.9 MW of EFORd offer segments. Only 4.3 MW, from multiple resources, were unoffered into the RPM Auction, which had no effect on either the RTO or LDA resource-clearing prices. No new generating units were offered in the auction.

The downward sloping demand curve resulted in more capacity cleared in the market than the reliability requirement. The 129,409.2 unforced MW of cleared resources for the entire RTO represented a reserve margin of 19.8 percent, which was 3,604.2 MW greater than the reliability requirement of 125,805.0 MW (IRM of 15.0 percent).[58, 59, 60] As shown in Figure 5-7, the downward sloping demand curve resulted in a price of $40.80 per MW-day. Net excess was 5,240.5 MW, which was a decrease of 3,693.6 MW from the net excess of 8,934.1 MW on May 31, 2007. (See Table 5-15.) This decrease in net excess was mainly because of an increase in the RTO load forecast of 3,921.0 MW from 133,500.0 MW to 137,421.0 MW, effective June 1, 2007. Certified ILR was 1,636.3 MW.

As shown in Table 5-20, the net load price that LSEs will pay is $40.69 per MW-day in the RTO area not included in the constrained LDAs. This value is the final zonal capacity price. The final zonal capacity price is the resource-clearing price adjusted for differences between the certified ILR for the delivery year and the forecasted RTO ILR obligation.

57 FRR entities are allowed to offer into the RPM Auction excess volumes above their FRR quantities, subject to a sales' cap amount. The 35.8 MW are excess volumes included in the sales' cap amount which were not offered into the auction.

58 Both the reserve margin calculation and IRM include FRR resources and FRR load and are on an ICAP basis.

59 The RTO reliability requirement, which is after FRR adjustments, is plotted on the variable resource requirement (VRR) curve as the reliability requirement less the ILR forecast obligation plus any FRR DR.

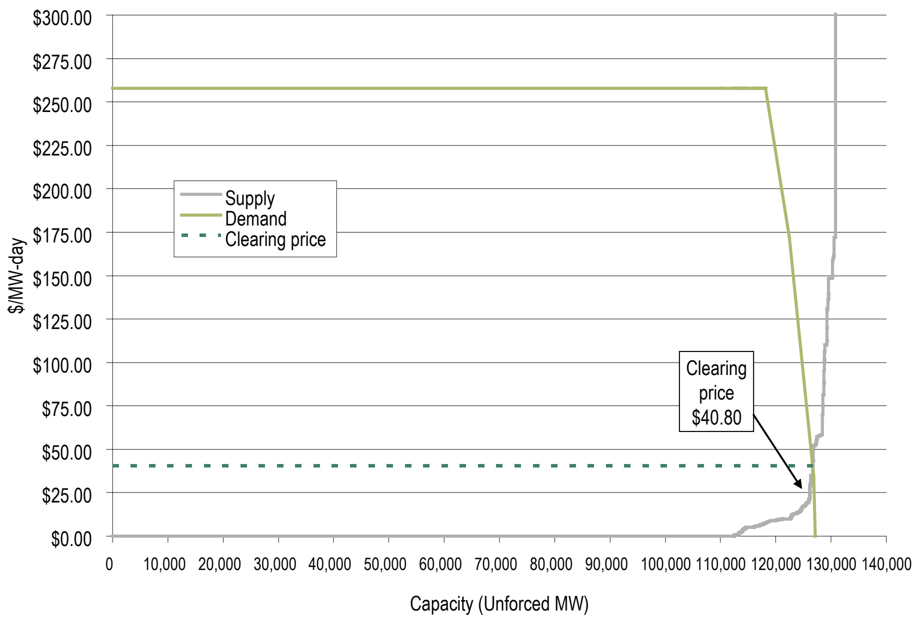
60 The demand curve UCAP quantities are based on three points, which are ratios of the installed reserve margin (IRM =15.0 percent) times the reliability requirement, less the forecast RTO ILR obligation. For the three points, the ratios are 1.12/1.15, 1.16/1.15 and 1.20/1.15. For these three points the UCAP prices are based on factors multiplied by net cost of net entry (CONE) divided by one minus the pool-wide EFORd. Net CONE is defined as CONE minus the energy and ancillary service revenue offset (E&AS). For the three points, the factors are 1.5, 1.0 and 0.2. For 2007/2008, CONE was $197.29 per MW-day and E&AS was $36.02 MW-day.

Table 5-20 RTO offer statistics: 2007/2008 RPM Auction[61]

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal RTO capacity (gen and DR)	165,111.2	155,206.0		
FRR	(24,717.0)	(22,922.6)		
Imports	2,983.8	2,809.2		
RPM capacity	143,378.0	135,092.6		
Exports	(4,373.9)	(3,938.5)		
FRR optional	(43.0)	(35.8)		
Excused	(463.4)	(270.3)		
Available	138,497.7	130,848.0	100.0%	100.0%
Generation offered	138,369.0	130,716.1	99.9%	99.9%
DR offered	123.5	127.6	0.1%	0.1%
Total offered	138,492.5	130,843.7	100.0%	100.0%
Unoffered	5.2	4.3	0.0%	0.0%
Cleared in RTO	134,034.1	126,666.7	96.8%	96.8%
Cleared in LDAs	2,949.5	2,742.5	2.1%	2.1%
Total cleared	136,983.6	129,409.2	98.9%	98.9%
Uncleared in RTO	1,479.1	1,405.1	1.1%	1.1%
Uncleared in LDAs	29.8	29.4	0.0%	0.0%
Total uncleared	1,508.9	1,434.5	1.1%	1.1%
Reliability requirement		125,805.0		
Total cleared		129,409.2		
ILR certified		1,636.3		
Net excess/(deficit)		5,240.5		
Resource clearing price ($ per MW-day)		$40.80	A	
Final zonal capacity price ($ per MW-day)		$40.69	B	
Final zonal CTR credit rate ($ per MW-day)		$0.00	C	
Final zonal ILR price ($ per MW-day)		$40.80	A-C	
Net load price ($ per MW-day)		$40.69	B-C	

61 Prices are only for those generating units outside of EMAAC and SWMAAC.

Figure 5-7 RTO market supply/demand curves: 2007/2008 RPM Auction[62, 63]



EMAAC

Table 5-21 shows total EMAAC offer data for the 2007/2008 RPM Auction. Total internal EMAAC unforced capacity of 30,825.1 MW includes all generating units and DR that qualified as a PJM capacity resource, excluding external units, and also includes owners' modifications to ICAP ratings. Including imports of 15.9 MW into EMAAC, RPM unforced capacity was 30,841.0 MW. This amount was reduced by 13.3 MW which were excused from the RPM must-offer requirement as a result of generation moving behind the meter, resulting in 30,827.7 MW that were available to be offered into the auction. Only 0.5 MW were unoffered into the RPM Auction, which had no effect on either the RTO or LDA resource-clearing prices.

Of the 30,797.8 MW cleared in EMAAC, 28,705.4 MW were cleared in the RTO before EMAAC became constrained. Once the constraint was binding, based on the 5,845.0 MW CETL value, only the incremental supply located in EMAAC was available to meet the incremental demand in the LDA. Of the 2,121.8 MW of incremental supply, 2,092.4 MW cleared, which resulted in a resource-clearing price of $197.67 per MW-day, as shown in Figure 5-8. The price was determined by the intersection of the incremental supply and demand curves. The uncleared MW were the result of offer prices which exceeded the demand curve.

62 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve excludes incremental demand which cleared in EMAAC and SWMAAC.

63 For ease of viewing, the graph was truncated at $300.00 per MW-day and does not show an uncleared offer of approximately $800.00 per MW-day.

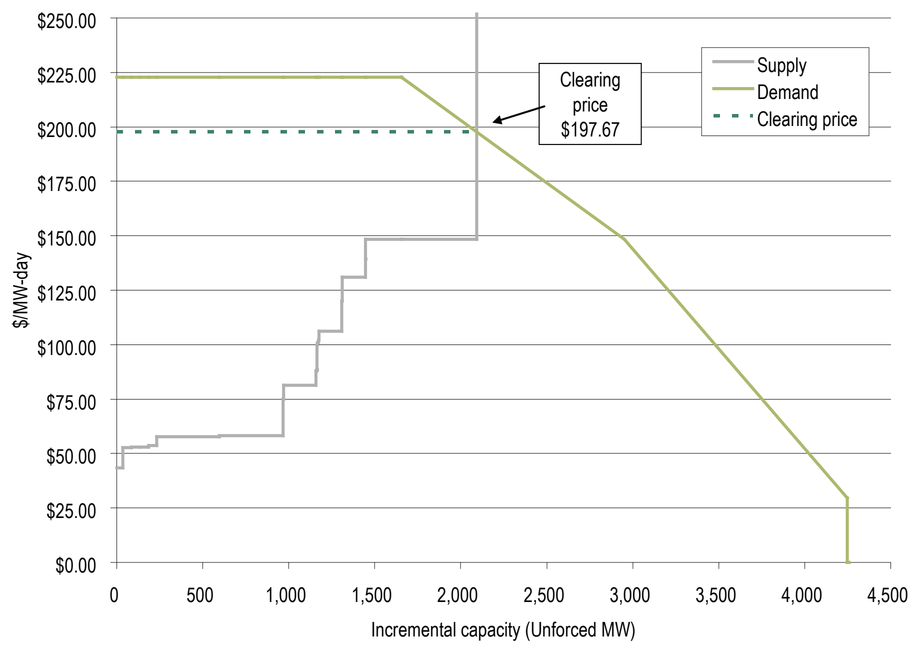
Total resources in EMAAC were 36,642.8 MW, which when combined with certified ILR of 387.0 MW resulted in a net excess of -206.9 MW (0.6 percent) less than the reliability requirement of 37,236.7 MW.

As shown in Table 5-21, the net load price that LSEs will pay is $177.00 per MW-day. This value is the final zonal capacity price ($197.16 per MW-day) less the final CTR credit rate ($20.16 per MW-day). The CTR MW value allocated to load in an LDA is the LDA UCAP obligation less the cleared generation internal to the LDA less the ILR forecast for the LDA. This MW value is multiplied by the locational price adder for the LDA to arrive at the economic value of the CTRs allocated to the load in the LDA. This value is then divided by the LDA UCAP obligation to arrive at the final CTR credit rate for the LDA. The final CTR credit rate is an allocation of the economic value of transmission import capability that exists in constrained LDAs and serves to offset a portion of the locational price adder charged to load in constrained LDAs.

Table 5-21 EMAAC offer statistics: 2007/2008 RPM Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal EMAAC capacity (gen and DR)	32,942.3	30,825.1		
Imports	15.9	15.9		
RPM capacity	32,958.2	30,841.0		
Exports	0.0	0.0		
Excused	(14.1)	(13.3)		
Available	32,944.1	30,827.7	100.0%	100.0%
Generation offered	32,900.2	30,782.5	99.9%	99.9%
DR offered	43.3	44.7	0.1%	0.1%
Total offered	32,943.5	30,827.2	100.0%	100.0%
Unoffered	0.6	0.5	0.0%	0.0%
Cleared in RTO	30,634.2	28,705.4	93.0%	93.1%
Cleared in LDA	2,279.5	2,092.4	6.9%	6.8%
Total cleared	32,913.7	30,797.8	99.9%	99.9%
Uncleared	29.8	29.4	0.1%	0.1%
Reliability requirement		37,236.7		
Total cleared		30,797.8		
CETL		5,845.0		
Total resources		36,642.8		
ILR certified		387.0		
Net excess/(deficit)		(206.9)		
Resource clearing price ($ per MW-day)		$197.67	A	
Final zonal capacity price ($ per MW-day)		$197.16	B	
Final zonal CTR credit rate ($ per MW-day)		$20.16	C	
Final zonal ILR price ($ per MW-day)		$177.51	A-C	
Net load price ($ per MW-day)		$177.00	B-C	

Figure 5-8 EMAAC incremental supply/demand curves: 2007/2008 RPM Auction[64]



SWMAAC

Table 5-22 shows total SWMAAC offer data for the 2007/2008 RPM Auction. Total internal SWMAAC unforced capacity of 10,352.2 MW includes all generating units and DR that qualified as a PJM capacity resource, excluding external units, and also includes owners' modifications to ICAP ratings. Since there were no imports from outside PJM into SWMAAC, RPM unforced capacity was 10,352.2 MW. This amount was reduced by 151.0 MW which were excused from the RPM must-offer requirement as a result of environmental regulations, resulting in 10,201.2 MW that were available to be offered into the auction. All capacity resources were offered into the RPM Auction.

Of the 10,201.2 MW cleared in SWMAAC, 9,551.1 MW had cleared in the RTO before SWMAAC became constrained. Once the constraint was binding, based on the 5,699.0 CETL value, only the incremental supply in SWMAAC was available to meet incremental demand in the LDA. All of the 650.1 MW of incremental supply cleared, but since there was not enough incremental supply to meet incremental demand, the resource-clearing price of $188.54 per MW-day was set by the demand curve. (See Figure 5-9.)

Total resources in SWMAAC were 15,900.2 MW, which when combined with certified ILR of 273.4 MW resulted in a net excess of 98.3 MW (0.6 percent) greater than the reliability requirement of 16,075.3 MW.

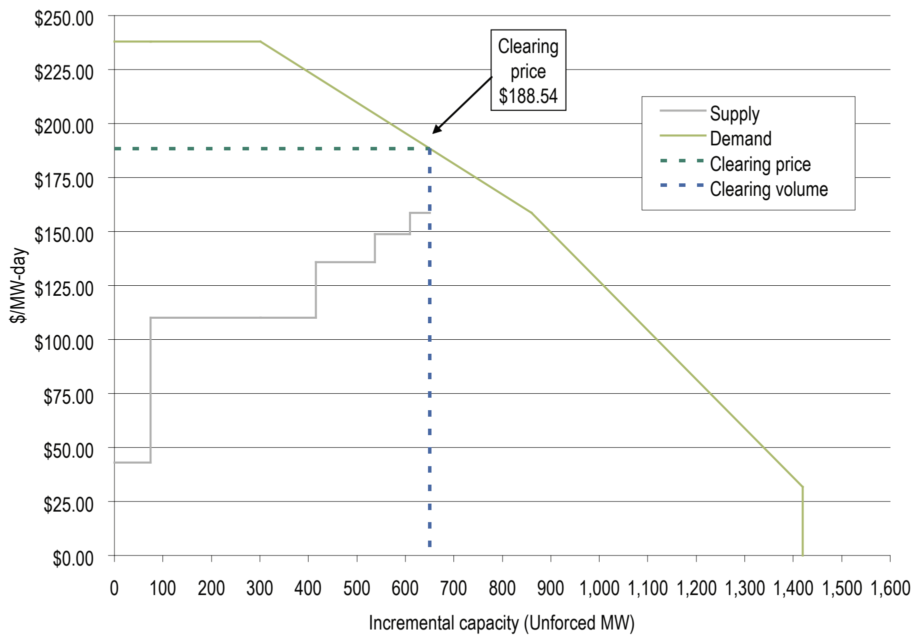
As shown in Table 5-22, the net load price that LSEs will pay is $139.67 per MW-day. This value is the final zonal capacity price ($188.05 per MW-day) less the final CTR credit rate ($48.38 per MW-day).

64 The supply curve was truncated at $250.00 per MW-day and does not show an uncleared offer of approximately $800.00 per MW-day.

Table 5-22 SWMAAC offer statistics: 2007/2008 RPM Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal SWMAAC capacity (gen and DR)	11,546.1	10,352.2		
Imports	0.0	0.0		
RPM capacity	11,546.1	10,352.2		
Exports	0.0	0.0		
Excused	(316.0)	(151.0)		
Available	11,230.1	10,201.2	100.0%	100.0%
Generation offered	11,211.1	10,181.5	99.8%	99.8%
DR offered	19.0	19.7	0.2%	0.2%
Total offered	11,230.1	10,201.2	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	10,560.1	9,551.1	94.0%	93.6%
Cleared in LDA	670.0	650.1	6.0%	6.4%
Total cleared	11,230.1	10,201.2	100.0%	100.0%
Uncleared	0.0	0.0	0.0%	0.0%
Reliability requirement		16,075.3		
Total cleared		10,201.2		
CETL		5,699.0		
Total resources		15,900.2		
ILR certified		273.4		
Net excess/(deficit)		98.3		
Resource clearing price ($ per MW-day)		$188.54	A	
Final zonal capacity price ($ per MW-day)		$188.05	B	
Final zonal CTR credit rate ($ per MW-day)		$48.38	C	
Final zonal ILR price ($ per MW-day)		$140.16	A-C	
Net load price ($ per MW-day)		$139.67	B-C	

Figure 5-9 SWMAAC incremental supply/demand curves: 2007/2008 RPM Auction



Generator Performance

Generator performance is a function of incentives from energy and capacity markets as well as the physical nature of the units and the level of expenditures made to maintain the capability of the units. Generator performance can be measured using indices calculated from historical data. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates). In state of the market reports prior to 2006, the generator performance analysis was based solely on the capacity resources in the PJM Mid-Atlantic Region and the AP Control Zone. The generator performance analysis for the *2006 State of the Market Report* and the *2007 State of the Market Report* includes all PJM capacity resources for which there are data in the PJM GADS database.[65]

Generator Performance Factors

Generator performance factors are based on a defined period, usually a year, and are directly comparable.[66] Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of

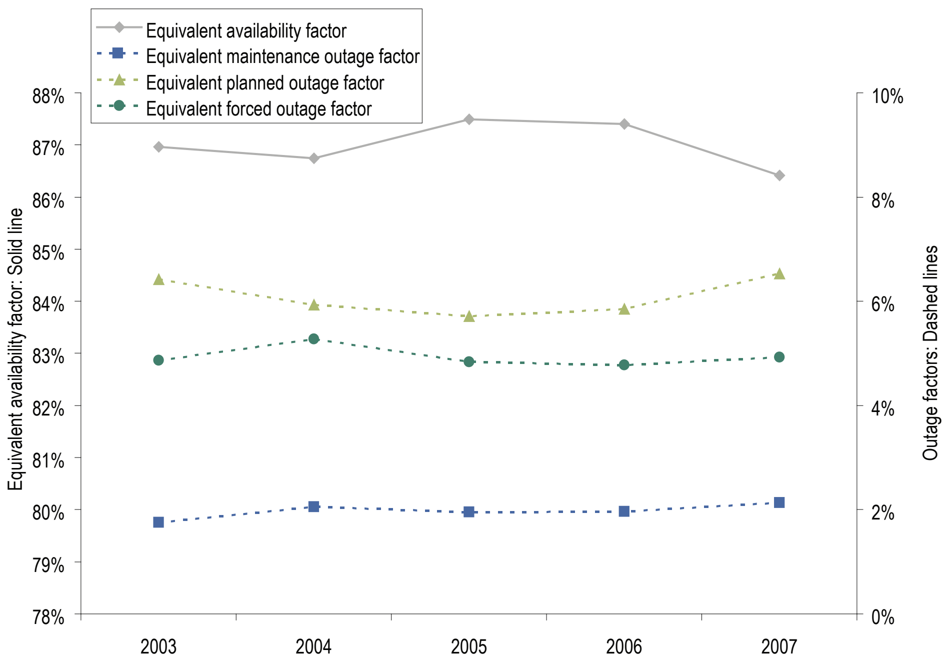
65 This set of capacity resources may include generators in addition to those in the set of generators committed as resources in the RPM.

66 Data from all PJM capacity resources for the years 2003 through 2007 were analyzed.

maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF decreased from 87.4 percent in 2006 to 86.4 percent in 2007. The EFOF increased by 0.1 percentage points from 2006 to 2007 while the EPOF increased by about 0.7 percentage points and the EMOF increased 0.2 percentage points.[67] (See Figure 5-10.)

Figure 5-10 PJM equivalent outage and availability factors: Calendar years 2003 to 2007



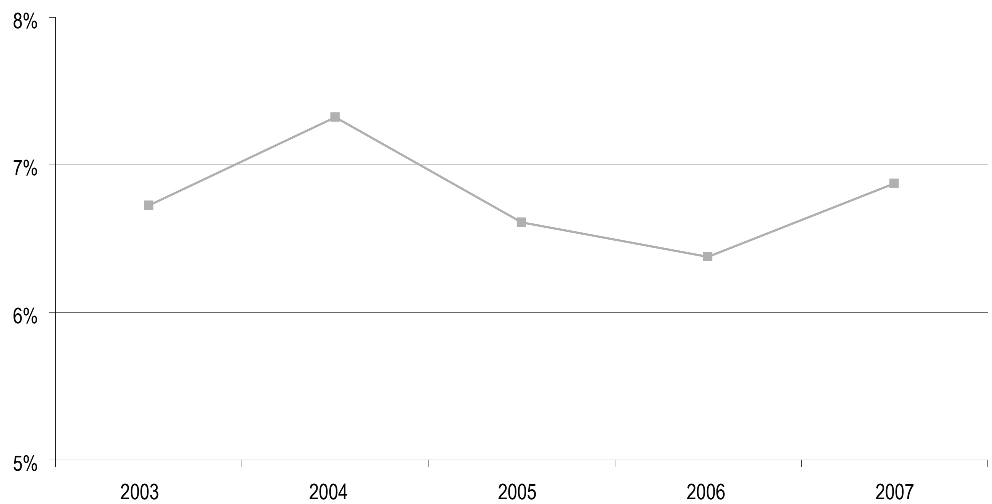
Generator Forced Outage Rates

The equivalent demand forced outage rate (EFORd) (generally referred to as the forced outage rate) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd is calculated using historical performance data. Unforced capacity for any individual generating unit is equal to one minus the EFORd multiplied by the unit's net dependable summer capability. The PJM Capacity Market creates an incentive to minimize the forced outage rate because the amount of capacity resources available to sell from a unit (i.e., unforced capacity) is inversely related to the forced outage rate.

67 The performance factor data include all units from the PJM Control Area. Data for the year 2007 may be incomplete as of the download date as corrections can be made at any time with permission from the PJM GADS administrators. Data are for 12 months ended December 31, 2007, as downloaded from the PJM GADS database on January 23, 2008.

EFORd[68] calculations use historical data, including equivalent forced outage hours,[69] service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[70] The average PJM EFORd increased from 6.7 percent in 2003 and 7.3 percent in 2004 before it decreased to 6.6 percent in 2005 and 6.4 percent in 2006 and again increased to 6.9 in 2007.[71] Figure 5-11 shows the average EFORd since 2003 for all units in the PJM Control Area.

Figure 5-11 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2003 to 2007[72]



68 EFORd was calculated using data for all units contained in the PJM GADS database. PJM systemwide EFORd is a capacity-weighted average of individual unit EFORd.

69 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.

70 See PJM. "Manual 22: Generator Resource Performance Indices," Revision 15 (June 1, 2007), Equations 2 through 5.

71 Data are for the 12 months ended December 31, 2007, as downloaded from the PJM GADS database on January 23, 2008. Data for the year 2007 may be incomplete as of the download date as corrections can be made at anytime with permission from PJM GADS administrators.

72 Data for 2003 are incomplete for some units in newly integrated areas. Available information supports the conclusion that there is no significant impact on the results of the analysis.

Components of Change in EFORd

Table 5-23 shows the contribution of each unit type to the system EFORd, calculated as the total forced MW for the unit type divided by the total capacity of the system.[73] Forced MW for a unit type is the EFORd multiplied by the generator's net dependable summer capability.

Table 5-23 Contribution to EFORd for specific unit types (Percentage points): Calendar years 2003 to 2007[74]

	2003	2004	2005	2006	2007	Change in 2007 from 2006
Combined cycle	0.4	0.6	0.7	0.5	0.4	(0.1)
Combustion turbine	1.1	1.3	1.5	1.4	1.7	0.3
Diesel	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.1	0.2	0.1	0.1	0.1	0.0
Nuclear	0.6	0.6	0.3	0.3	0.3	0.0
Steam	4.4	4.6	4.0	4.0	4.3	0.3
Total	6.7	7.3	6.6	6.4	6.9	0.5

The increase in overall PJM Control Area EFORd of 0.5 percentage points (a 7.8 percent increase) between 2006 and 2007 resulted primarily from poorer performance of combustion turbine units (494 generating units) and steam units (317 generating units) which together accounted for 0.6 of the 0.5 percentage point overall increase.[75] This increase was partially offset by the improved performance of combined-cycle units (106 generating units).

Of the 1,216 generating units in the EFORd analysis, during calendar year 2007, 283 units had decreased EFORds, 532 units had increased EFORds and the remaining 401 units had unchanged EFORds. If the 283 units with lower forced outage rates had not experienced rates lower than the average, the 2007 EFORd would have been 9.3 percent.

Changes in outage rates by unit type and changes in capacity by unit type combined to produce the observed impacts on system EFORd. Since total capability from both combustion turbine and fossil steam units remained nearly the same from year to year, the increased forced outage rates for these unit types were the reason for their contribution to the increased system EFORd.

Table 5-24 shows the relative contributions of EFORd and capacity to EFORd levels by unit type and for the system. Approximately 117 percent of the contribution of combustion turbine units to the increased combustion turbine EFORd was the result of increased combustion turbine EFORd while minus 17 percent of the contribution of combustion turbine units to the increased combustion turbine EFORd was the result of lower capacity levels for combustion turbines. Approximately minus 3 percent of the contribution of

73 The generating unit types are: steam, nuclear, diesel, combustion turbine, combined-cycle and hydroelectric. For all tables, run of river and pumped storage hydroelectric are combined into a single hydroelectric category.

74 Calculated values presented in Section 5, "Capacity Market," "Generator Performance" are based on unrounded, underlying data and may differ from those derived from the rounded values shown in the tables.

75 A single unit may include more than one set of generator terminals aggregated as a single generator.

combined-cycle units to the decreased combined-cycle EFORd was the result of increased combined-cycle capacity while 103 percent of the contribution of combined-cycle units to the decreased combined-cycle EFORd was the result of lower EFORd levels for combined-cycle units. Overall, 119 percent of the increase in EFORd from 2006 to 2007 was the result of increased EFORd for specific unit types while the balance was the result of the change in the mix of capacity by unit type.

Table 5-24 Percent change in contribution to EFORd (Unit type): 2007 compared to 2006

	Contribution Change Due to Capacity	Contribution Change Due to EFORd
Combined cycle	(3.2%)	103.2%
Combustion turbine	(16.7%)	116.7%
Diesel	17.3%	82.7%
Hydroelectric	(18.3%)	118.3%
Nuclear	1.5%	98.5%
Steam	(16.6%)	116.6%
All unit types	(18.8%)	118.8%

Table 5-25 Five-year PJM EFORd data comparison to NERC five-year average for different unit types: Calendar years 2003 to 2007

	2003	2004	2005	2006	2007	NERC 2002 to 2006
Combined cycle	5.4%	5.5%	5.3%	4.2%	3.2%	6.2%
Combustion turbine	8.1%	8.7%	9.8%	9.3%	11.5%	10.7%/10.1%
Diesel	7.9%	8.9%	14.0%	13.1%	11.4%	11.1%
Hydroelectric	2.2%	3.9%	2.5%	1.9%	2.0%	3.2%
Nuclear	3.2%	3.2%	1.6%	1.4%	1.7%	4.1%
Steam	8.3%	9.2%	8.1%	8.2%	8.7%	7.1%
Overall	6.7%	7.3%	6.6%	6.4%	6.9%	NA

Table 5-25 compares PJM EFORd data by unit type to North American Electric Reliability Council (NERC) data for corresponding unit types.[76] The 2007 PJM forced outage rates for combined-cycle, hydroelectric and nuclear units were below the NERC five-year averages. The 2007 PJM EFORd for diesel, combustion turbine and fossil steam units exceeded the NERC averages.[77]

Duty Cycle and EFORd

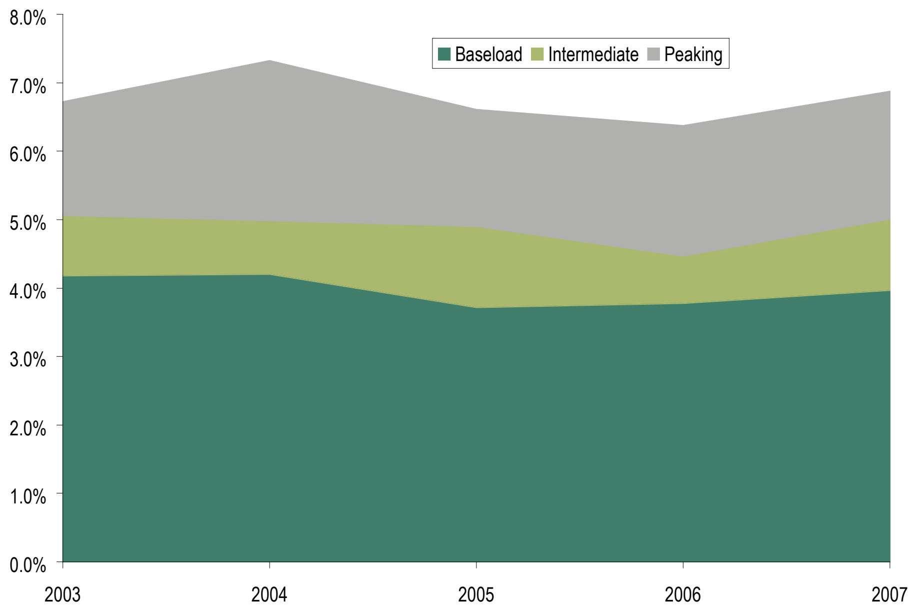
In addition to disaggregating system EFORd by unit type, units were categorized by actual duty cycles as baseload, intermediate or peaking to determine the relationship between type of operation and forced

76 The PJM data include all combustion turbines as a single unit type.

77 NERC defines combustion turbines in two categories: jet engines and gas turbines. Their EFORd for the 2002 to 2006 period are 10.7 percent and 10.1 percent, respectively, per NERC's GADS "2002-2006 Generating Unit Statistical Brochure - Units Reporting Events" <ftp://ftp.nerc.com/pub/sys/all_updl/gads/gar/2002_2006_Generating_Unit_Statistical_Brochure_Unit_Reporting_Events.zip> (28 KB). Also, the NERC average for fossil steam units is a unit-year-weighted value for all units reporting. The PJM Control Area values are weighted by capability for each calendar year.

outage rates.[78] Figure 5-12 shows the contribution of unit types to system average EFORd. In 2007, of 22,600 MW of combined-cycle units, approximately 20,700 MW are in the intermediate (18,100 MW) and peaking (2,600 MW) classes. Of 27,200 MW of combustion turbine units approximately 26,700 MW are in the intermediate (1,900 MW) and peaking (24,800 MW) classes.

Figure 5-12 Contribution to EFORd by duty cycle: Calendar years 2003 to 2007



Forced Outage Analysis

The MMU analyzed the causes of forced outages for the entire PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[79] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor.

The PJM EAF for 2007 was 86.4 percent; the corresponding EMOF and EPOF were 2.1 percent and 6.5 percent, respectively. As a result, the 2007 PJM EFOF was 4.9 percent. This means 4.9 percent lost availability because of forced outages.

The major reasons for this lost equivalent availability are listed in Table 5-26.

78 Duty cycle is the time the unit is generating divided by the time the unit is available to generate. A baseload unit is defined as a unit that generates during 50 percent or more of its available hours. An intermediate unit is defined as a unit that generates during from 10 percent to 50 percent of its available hours. A peaking unit is defined as a unit that generates during less than 10 percent of its available hours. These terms were defined for the purposes of this analysis.

79 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a systemwide basis.

Table 5-26 Outage cause contribution to PJM EFOF: Calendar year 2007

	Percentage Point Contribution to EFOF	Contribution to EFOF
Boiler tube leaks	1.08	21.9%
Electrical	0.25	5.0%
Performance	0.20	4.0%
Boiler fuel supply from bunkers to boiler	0.20	4.0%
Miscellaneous (jet engine)	0.16	3.2%
Boiler air and gas systems	0.16	3.2%
Feedwater system	0.16	3.2%
Economic	0.14	2.8%
Miscellaneous (generator)	0.12	2.5%
Miscellaneous (steam turbine)	0.12	2.5%
Stack emission	0.10	2.1%
Boiler piping system	0.10	2.0%
Generator	0.10	2.0%
Controls	0.10	2.0%
Miscellaneous (gas turbine)	0.09	1.9%
Cooling system	0.09	1.9%
Auxiliary systems	0.09	1.9%
Regulatory	0.09	1.8%
Fuel quality	0.08	1.7%
All other causes	1.50	30.4%
PJM EFOF 2007	4.93	100.0%

Table 5-26 shows that boiler tube leaks, at 21.9 percent of the systemwide EFOF, were the largest single contributor to EFOF. Forced outages because of boiler tube leaks reduced system equivalent availability by 1.08 percentage points. Electrical problems caused the second largest reduction to equivalent availability by 0.25 percentage points. Performance caused the third largest reduction to equivalent availability by 0.20 percentage points. Almost all of this reduction was attributable to failing, in whole or in part, PJM seasonal capacity verification tests which require an outage until the problem is solved or the generator takes a capacity derating.

Table 5-27 Contribution to EFOF by unit type for the most prevalent causes: Calendar year 2007

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler tube leaks	0.4%	0.0%	0.0%	0.0%	0.0%	29.9%	21.9%
Electrical	4.0%	12.0%	3.8%	1.9%	2.2%	4.0%	5.0%
Performance	15.1%	13.1%	4.1%	7.1%	1.7%	1.5%	4.0%
Boiler fuel supply from bunkers to boiler	0.5%	0.0%	0.0%	0.0%	0.0%	5.4%	4.0%
Miscellaneous (jet engine)	0.0%	22.7%	0.0%	0.0%	0.0%	0.0%	3.2%
Boiler air and gas systems	0.0%	0.0%	0.0%	0.0%	0.0%	4.4%	3.2%
Feedwater system	2.4%	0.0%	0.0%	0.0%	6.9%	3.6%	3.2%
Economic	1.6%	4.3%	0.1%	3.4%	0.0%	2.8%	2.8%
Miscellaneous (generator)	8.9%	5.0%	12.9%	5.9%	1.2%	1.6%	2.5%
Miscellaneous (steam turbine)	2.5%	0.0%	0.0%	0.0%	1.4%	3.1%	2.5%
Stack emission	0.1%	1.0%	0.7%	0.0%	0.0%	2.6%	2.1%
Boiler piping system	7.4%	0.0%	0.0%	0.0%	0.0%	2.2%	2.0%
Generator	2.3%	0.8%	0.1%	23.8%	0.0%	2.0%	2.0%
Controls	3.8%	0.4%	0.0%	2.3%	4.6%	1.9%	2.0%
Miscellaneous (gas turbine)	7.1%	10.7%	0.0%	0.0%	0.0%	0.0%	1.9%
Cooling system	1.1%	0.2%	0.0%	0.0%	4.4%	2.2%	1.9%
Auxiliary systems	2.8%	9.3%	0.0%	0.3%	0.3%	0.5%	1.9%
Regulatory	0.0%	0.0%	1.4%	0.0%	0.0%	2.4%	1.8%
Fuel quality	0.7%	0.1%	3.3%	0.0%	0.0%	2.3%	1.7%

Table 5-27 shows the major causes of EFOF by unit type. Boiler tube leaks caused 29.9 percent of the EFOF for fossil steam units. Feedwater system problems caused 6.9 percent of the EFOF for nuclear units. Generator outages caused 23.8 percent of the EFOF for hydroelectric units.

Table 5-28 Contribution to EFOF by unit type: Calendar year 2007

	EFOF	Contribution to EFOF
Combined cycle	2.1%	5.7%
Combustion turbine	4.7%	14.2%
Diesel	9.1%	0.4%
Hydroelectric	1.5%	1.1%
Nuclear	1.5%	5.4%
Steam	7.3%	73.2%
PJM systemwide	4.9%	100.0%

The contribution to systemwide EFOF by a generator or group of generators is a function of duty cycle, EFORd and share of the systemwide capacity mix. For example, fossil steam units have the largest share (about 49 percent) of the capacity mix,[80] have a high duty cycle and in 2007 had an EFORd of 8.7 percent

80 See the *2007 State of the Market Report*, Volume II, Section 3, “Energy Market, Part 2,” “Existing and Planned Generation,” at Table 3-38, “PJM capacity age (MW).”

which yields a 73.2 percent contribution to PJM systemwide EFOF. Nuclear units also have a high duty cycle; their share of the PJM systemwide capacity mix is about 18 percent and in 2007 they had a 1.7 percent EFORd which yields a 5.4 percent contribution to PJM systemwide EFOF. By using the values in Table 5-28 and Table 5-27 one can determine how much the individual unit types' causes contributed to PJM systemwide EFOF. For instance the value for boiler tube leaks in Table 5-27 multiplied by the contribution value in Table 5-28 for the same unit type will yield the percent contribution to the PJM systemwide EFOF for that outage cause.

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages that should be deemed outside management control (OMC) in response to the system disturbance of August 14, 2003.[81] NERC specified, in its January 2006 update to the "Generator Availability Data System Data Reporting Instructions,"[82] in Appendix K,[83] that each OMC outage must be carefully considered as to its cause and nature. An outage can be classified as an OMC outage only if the generating unit outage was caused by other than failure of the owning company's equipment or other than the failure of the practices, policies and procedures of the owning company. Appendix K of the "Generator Availability Data Systems Data Reporting Instructions" lists specific cause codes (i.e., codes that are standardized for specific outage causes) that would be considered OMC outages.[84] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, fuel quality issues (i.e., codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered per the NERC directive. In 2007, PJM removed the OMC designation from all of the fuel quality codes with the exception of 9250, "low Btu coal" since only that code had both an OMC and non-OMC code (i.e., 9250, OMC code for "low Btu coal"; 9251, non-OMC code for "low Btu coal"). After analyzing the data for these outages types, it was found that in 2006, of 17 companies that used either of these cause codes, only three had used both the OMC and non-OMC cause codes. In other words, 14 companies exclusively used the OMC cause code. In 2007, however, of 39 companies that used either of the OMC and non-OMC fuel quality cause codes, only one company exclusively used the OMC cause code. In 2006, approximately 51 percent of the lost generation because of "low Btu coal" was deemed OMC by the generation owners. In 2007, only 6 percent of the lost generation because of "low Btu coal" was deemed OMC. It is not clear why some companies, in 2006, exclusively used the OMC cause codes and did not use the non-OMC cause code for "low Btu coal." In 2007, companies seem to have used the non-OMC and OMC cause codes for fuel quality more appropriately. It is a reasonable expectation that companies would monitor coal quality stringently and reject noncompliant shipments. It is also possible that these outages are a function of issues with generating plant equipment. PJM should scrutinize OMC outages for low Btu coal carefully to ensure that only appropriate outages are classified as OMC.

All outages, including OMC outages, are included in the EFORd that is used for planning studies that determine the reserve requirement. However, OMC outages will be excluded from the calculations used to

81 NERC had always provided cause codes for outages that were caused by external forces. However, as a result of the system disturbance on August 14, 2003, NERC specifically created outage specifications for outages that were "outside management control."

82 The "Generator Availability Data System Data Reporting Instructions" can be found on the NERC Web site: <ftp://ftp.nerc.com/pub/sys/all_updl/gads/dri/2008_GADS_DRI.pdf> (4.9 MB).

83 The "Generator Availability Data System Data Reporting Instructions," Appendix K can be found on the NERC Web site: <ftp://ftp.nerc.com/pub/sys/all_updl/gads/dri/apd-k_Outside_Plant_Management_Control.pdf> (161 KB).

84 For a list of these cause codes, see the *2007 State of the Market Report*, Volume II, Appendix E, "Capacity Market."

determine the level of unforced capacity for specific units and thus the amount of unforced capacity for sale in Capacity Markets. This modified EFORd is termed the XEFORd. All submitted OMC outages are reviewed by PJM's Capacity Adequacy Department. Table 5-29 shows the impact of OMC outages on EFORd for 2007. The difference is especially noticeable for peaking units (combustion turbines and diesels). Combustion turbine and diesel units have natural gas fuel curtailment outages deemed as OMC. If companies' natural gas fuel supply is curtailed because of pipeline issues, the event can be deemed OMC. However, natural gas curtailments caused by lack of firm transportation contracts or arbitraging transportation reservations should not be classified as OMC. In 2007, XEFORd was 0.7 percentage points less than EFORd, which translates into a 1,225 MW difference in unforced capacity.

Table 5-29 PJM EFORd vs. XEFORd: Calendar year 2007

	2007 EFORd	2007 XEFORd	Difference
Combined cycle	3.2%	3.1%	0.2%
Combustion turbine	11.5%	9.6%	1.9%
Diesel	11.4%	9.9%	1.5%
Hydroelectric	2.0%	1.7%	0.3%
Nuclear	1.7%	1.6%	0.1%
Steam	8.7%	8.1%	0.6%
Overall	6.9%	6.2%	0.7%