SECTION 5 – CAPACITY MARKET

Each organization serving PJM load must meet its capacity obligations by acquiring capacity resources through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can affect the financial consequences of purchasing capacity in the capacity market by constructing generation and offering it into the capacity market, by entering into bilateral contracts, by developing demand-side resources and Energy Efficiency (EE) resources and offering them into the capacity market, or by constructing transmission upgrades and offering them into the capacity market.

Overview

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for calendar year 2009, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.

RPM Capacity Market

Market Design

On June 1, 2007, the Reliability Pricing Model (RPM) Capacity Market design was implemented in the PJM region, replacing the Capacity Credit Market (CCM) design that had been in place since 1999.[1] The RPM design 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.

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future. Effective with the 2012/2013 delivery year, First, Second and Third Incremental Auctions (IA) are held for each delivery year.[2] Prior to the 2012/2013 delivery year, the second incremental auction is conducted if PJM determines than an unforced capacity resource shortage exceeds 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[3] Previously, First, Second, and Third Incremental Auctions were conducted 23, 13, and four months, respectively, prior to the delivery year. Also effective for the 2012/2013 delivery year, a conditional incremental auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.

1 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2009 State of the Market Report for PJM*, Section 5, "Capacity Market" and include all capacity within the PJM footprint.
2 126 FERC ¶61,275 (2009).
3 Docket No. ER10-366-000.

RPM prices are locational and may vary depending on transmission constraints.[4] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. 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 in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power, that define offer caps based on the marginal cost of capacity and that have flexible criteria for competitive offers by new entrants or by entrants that have an incentive to exercise monopsony power. Demand-side resources and Energy Efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **Supply.** Total internal capacity increased 350.2 MW from 156,968.0 MW on June 1, 2008, to 157,318.2 MW on June 1, 2009.[5] This increase was the result of 439.2 MW of new generation, 74.1 MW of generation uprates, 220.6 MW of demand resource (DR) mods, and a decrease of 383.7 MW due to higher EFORds.

  In the 2010/2011, 2011/2012, and 2012/2013 auctions, new generation increased 3,271.9 MW; 651.9 MW came out of retirement and net generation deratings were 2,994.9 MW, for a total of 928.9 MW. DR and Energy Efficiency (EE) offers increased 9,409.3 MW through June 1, 2012. A decrease of 890.3 MW was due to higher EFORds. The reclassification of the Duquesne resource as internal added 3,187.2 MW to total internal capacity. The net effect from June 1, 2009, through June 1, 2012, was an increase in total internal capacity of 12,635.1 MW (8.0 percent) from 157,318.2 MW to 169,953.3 MW.

  In the 2009/2010 auction, 17 more generating resources made offers than in the 2008/2009 RPM Auction. The increase consisted of 11 new resources (439.2 MW), nine resources that were previously entirely FRR committed (82.5 MW), two less resources exported (698.6 MW), and two fewer resources excused from offering into the auction (37.3 MW) offset by five excused resources (44.5 MW), one less external resource that did not offer (60.4 MW), and one additional resource committed fully to FRR (10.0 MW). The new resources consisted of eight new CT resources (380.2 MW), two new diesel resources (9.2 MW) and one new steam resource (49.8 MW).

4 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.

5 Unless otherwise specified, all volumes are in terms of UCAP.

In the 2010/2011 auction, 11 more generating resources made offers than in the 2009/2010 RPM auction. The increase consisted of 15 new resources (406.9 MW), four reactivated resources (161.7 MW), three that were previously entirely FRR committed (10.9 MW), one less resource excused from offering (3.9 MW), and one less resource entirely exported (39.9 MW), offset by four deactivated resources (59.6 MW), four resources exported from PJM (554.0 MW), three retired resources (348.4 MW), and two resources excused from offering (108.8 MW). The new resources consisted of seven CT resources (270.5 MW), five new wind resources (120.0 MW), three new diesel resources (16.4 MW), and four reactivated resources (165.0 MW).

In the 2011/2012 auction, 21 more generating resources made offers than in the 2010/2011 RPM auction. The increase consisted of 20 new resources (2,203.7 MW), four reactivated resources (486.9 MW), three fewer excused resources (126.3 MW), and one additional resource imported (663.2 MW), offset by five additional resources committed fully to FRR (1.0 MW) and two retired resources (87.3 MW). The new resources consisted of 11 new CT resources (728.7 MW), four new wind resources (75.2 MW), two new steam resources (838.0 MW), one new combined cycle resource (556.5 MW), one new diesel resource (4.2 MW) and one new solar resource (1.1 MW).

In the 2012/2013 auction, eight more generating resources made offers than in the 2011/2012 RPM auction. The net increase of eight resources consisted of 16 new resources (772.5 MW), four resources that were previously entirely FRR committed (13.4 MW), three additional resources imported (276.8 MW), two additional resources resulting from disaggregation of RPM resources, and one resource formerly unoffered (1.9 MW), offset by nine retired resources (1,044.5 MW), four additional resources committed fully to FRR (39.5 MW), four less resources resulting from aggregation of RPM resources, and one less external resource that did not offer (663.2 MW).[6] In addition, there were the following retirements of resources that were either exported or excused in the 2011/2012 BRA: two combustion turbine resources (5.3 MW) and three combined cycle resources (297.6 MW). Also, resources that are no longer PJM capacity resources consisted of three CT units (521.5 MW) in the RTO. The new units consisted of six new diesel resources (13.9 MW), four new wind resources (57.9 MW), three new steam units (560.4 MW), and three new CT units (140.3 MW).

- **Demand.** There was a 2,545.5 MW increase in the RPM reliability requirement from 150,934.6 MW on June 1, 2008 to 153,480.1 MW on June 1, 2009. On June 1, 2009, PJM Electricity distribution companies (EDCs) and their affiliates maintained a 79.6 percent market share of load obligations under RPM, down from 80.1 percent on June 1, 2008.

- **Market Concentration.** For the 2009/2010, 2010/2011, 2011/2012, and 2012/2013 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In the 2009/2010 BRA, 2009/2010 Third IA, 2010/2011 BRA, 2011/2012 BRA, and 2011/2012 First IA 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. In the 2012/2013 BRA, all participants in the RTO as well as MAAC, PSEG North, and DPL South RPM markets failed the TPS test. Six participants included in the incremental supply of EMAAC passed the test. Offer caps were applied to all sell offers that did not pass the test.

6 Disaggregation and aggregation of RPM resources reflect changes in how units are offered in RPM. For example, multiple units at a plant may be offered as a single unit or multiple units.

- **Imports and Exports.** Net exchange increased 1,688.3 MW from June 1, 2008 to June 1, 2009. Net exchange, which is imports less exports, increased due to an increase in imports of 45.1 MW and a decrease in exports of 1,643.2 MW.

- **Demand-Side and Energy Efficiency Resources.** Under RPM, demand-side resources in the Capacity Market increased by 3,206.9 MW from 4,167.5 MW on June 1, 2008 to 7,374.4 MW on June 1, 2009. Prior to the 2012/2013 delivery year, demand-side resources included DR cleared in the RPM Auctions and certified/forecast interruptible load for reliability (ILR). For delivery years 2012/2013 and beyond, ILR was eliminated and demand-side resources include DR and Energy Efficiency (EE) resources.

- **Net Excess.** Net excess increased 3,254.4 MW from 5,011.1 MW on June 1, 2008 to 8,265.5 MW on June 1, 2009.

Market Conduct

- **2009/2010 RPM Base Residual Auction.** Of the 1,093 generating resources which submitted offers, unit-specific offer caps were calculated for 151 resources (13.8 percent). Offer caps of all kinds were calculated for 550 resources (50.3 percent), of which 377 were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2009/2010 Third Incremental Auction.** Of the 267 generating resources which submitted offers, 255 resources chose the offer cap option of 1.1 times the BRA clearing price (95.5 percent).[7] Unit-specific offer caps were calculated for two resources (0.7 percent). Offer caps of all kinds were calculated for five resources (1.9 percent), of which one was based on the technology specific default (proxy) ACR calculated by the MMU.

- **2010/2011 RPM Base Residual Auction.** Of the 1,104 generating resources which submitted offers, unit-specific offer caps were calculated for 154 resources (13.9 percent). Offer caps of all kinds were calculated for 532 resources (48.1 percent), of which 370 were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2011/2012 RPM Base Residual Auction.** Of the 1,125 generating resources which submitted offers, unit-specific offer caps were calculated for 145 resources (12.9 percent). Offer caps of all kinds were calculated for 472 resources (42.0 percent), of which 303 were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2011/2012 RPM First Incremental Auction.** Of the 129 generating resources which submitted offers, unit-specific offer caps were calculated for 19 resources (14.8 percent). Offer caps of all kinds were calculated for 68 resources (52.8 percent), of which 47 were based on the technology specific default (proxy) ACR calculated by the MMU.

7 124 FERC ¶ 61,140 (2008).

- **2012/2013 RPM Base Residual Auction.**[8] Of the 1,133 generating resources which submitted offers, unit-specific offer caps were calculated for 120 resources (10.6 percent). Offer caps of all kinds were calculated for 607 resources (53.6 percent), of which 479 were based on the technology specific default (proxy) ACR calculated by the MMU.

Market Performance

2009/2010 RPM Base Residual Auction

- **RTO.** Total internal RTO unforced capacity of 157,318.2 MW includes all generating units and DR that qualified as a PJM capacity resource for the 2009/2010 RPM Base Residual Auction, excludes external units and reflects owners' modifications to installed capacity (ICAP) ratings. After accounting for FRR committed resources and imports, RPM capacity was 136,300.4 MW. The 132,231.8 MW of cleared resources for the entire RTO represented a reserve margin of 17.8 percent, which was 1,784.0 MW greater than the reliability requirement of 130,447.8 MW (installed reserve margin (IRM) of 15.0 percent) and resulted in a clearing price of $102.04 per MW-day.

  Total cleared resources in the RTO were 132,231.8 MW which resulted in a net excess of 8,265.5 MW, an increase of 3,254.4 MW from the net excess of 5,011.1 MW in the 2008/2009 RPM BRA. Certified interruptible load for reliability (ILR) was 6,481.5 MW.

  Cleared resources across the entire RTO will receive a total of $7.5 billion based on the unforced MW cleared and the prices in the 2009/2010 RPM BRA, an increase of approximately $1.4 billion from the 2008/2009 planning year.

- **MAAC+APS.**[9] Total internal MAAC+APS unforced capacity of 73,012.9 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 MAAC+APS, RPM unforced capacity was 73,102.2 MW.[10] Of the 5,764.9 MW of incremental supply, 5,314.7 MW cleared, which resulted in a resource-clearing price of $191.32 per MW-day.

  Total resources in MAAC+APS were 77,488.7 MW, which when combined with certified ILR of 3,081.0 MW resulted in a net excess of 2,666.8 MW (3.4 percent) greater than the reliability requirement of 77,902.9 MW.

- **SWMAAC.** Total internal SWMAAC unforced capacity of 10,345.2 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. Of the 2,413.7 MW of incremental supply, 2,016.6 cleared, which resulted in a resource-clearing price of $237.33 per MW-day.

8 For a more detailed analysis of the 2012/2013 RPM Base Residual Auction, see "Analysis of the 2012/2013 RPM Base Residual Auction" (August 6, 2009) <http://www.monitoringanalytics.com/reports/Reports/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090806.pdf>.

9 MAAC was an acronym for Mid-Atlantic Area Council, EMAAC was an acronym for Eastern Mid-Atlantic Area Council, and SWMAAC was an acronym for Southwestern Mid-Atlantic Area Council. MAAC no longer exists as its role was taken on by Reliabilty*First* Corporation. MAAC, EMAAC and SWMAAC are now regions of PJM.

10 Rules for RPM auctions state that imports are modeled in the unconstrained region of the RTO. See PJM. "Manual 18: PJM Capacity Market," Revision 6 (Effective June 18, 2009), p. 31, <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.25 MB). The import MW into MAAC+APS consist of MW under a grandfathered agreement related to Rural Electric Cooperatives (RECs) generation.

Total resources in SWMAAC were 16,305.6 MW, which when combined with certified ILR of 519.3 MW resulted in a net excess of 506.1 MW (3.1 percent) greater than the reliability requirement of 16,318.8 MW.

2009/2010 RPM Third Incremental Auction

- **RTO.** There were 3,255.8 MW offered into the Third Incremental Auction while buy bids totaled 2,697.6 MW. Cleared volumes in the RTO were 1,798.4 MW, resulting in an RTO clearing price of $40.00 per MW-day. The 1,457.4 MW of uncleared volumes can be used as replacement capacity or traded bilaterally.

  Cleared resources across the entire RTO will receive a total of $47.7 million based on the unforced MW cleared and the prices in the 2009/2010 RPM Third Incremental Auction.

- **MAAC+APS.** In MAAC+APS, 2,142.3 MW were offered into the auction while buy bids in MAAC+APS totaled 1,953.2 MW. Cleared volumes in MAAC+APS were 1,275.3 MW, resulting in a MAAC+APS clearing price of $86.00 per MW-day. The 867.0 MW of uncleared volumes can be used as replacement capacity or traded bilaterally.

- **SWMAAC.** Although SWMAAC was a constrained LDA in the 2009/2010 BRA, supply and demand curves resulted in a price less than the MAAC+APS clearing price. Supply offers in the incremental auction in SWMAAC (985.1 MW) exceeded SWMAAC demand bids (135.5 MW). The result was that all of SWMAAC supply which cleared received the MAAC+APS clearing price.

Generator Performance

- **Forced Outage Rates.** Average PJM EFORd remained constant at 7.5 percent in 2008 and 2009. PJM EFORp decreased from 4.5 percent in 2008 to 4.0 percent in 2009.[11] Average PJM EFORd was significantly affected by a single nuclear unit, AEP's Cook Nuclear Plant Unit 1, which was on forced outage for a majority of the year.[12] If this unit were excluded from the results, 2009 EFORd would decrease to 6.9 percent.

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor decreased from 86.5 percent in 2008 to 85.7 percent in 2009.

- **Outages Deemed Outside Management Control (OMC).** According to NERC criteria, an outage may 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. OMC outages are excluded from the calculation of the forced outage rate, termed the XEFORd, used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

11 2008 data is for the 12 months ended December 31, 2008, as downloaded from the PJM GADS database on February 23, 2010. 2009 data is for the year ending December 31, 2009, as downloaded from the PJM GADS database on February 23, 2010. Annual EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

12 "AEP´s Cook Nuclear Unit 1 Reaches Full Reactor Power." AEP press release, December 23, 2009. <http://www.aep.com/newsroom/newsreleases/?id=1582>.

Conclusion

Capacity Market Design and Scarcity Revenues

The wholesale power markets, in order to be viable, must be competitive and they must provide adequate revenues to ensure an incentive to invest in new capacity. A wholesale energy market will not consistently produce competitive results in the absence of local market power mitigation rules. This is the result, not of a fundamental flaw in the market design, but of the fact that transmission constraints in a network create local markets where there is structural market power. A wholesale energy market will not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity pricing. This is a result, not of offer capping, but of the fundamentals of wholesale power markets which must carry excess capacity in order to meet externally imposed reliability rules.

Scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The RPM design reflects the recognition that the energy markets, by themselves and in the absence of a carefully designed expansion of scarcity pricing, will not result in adequate revenues. The RPM design provides an alternate method for collecting scarcity revenues. The revenues in the capacity market are scarcity revenues.

The Definition of Capacity

In order for capacity markets to work, it is essential that the product definition be correct.

The definition of the capacity product is central to refining the market rules governing the sale and purchase of capacity. The current definition of capacity includes several components: the obligation to offer the energy of the unit into the Day-Ahead Market; the obligation to permit PJM to recall the energy from the unit under emergency procedures; the obligation to provide outage data to PJM; the obligation to provide energy during the defined high demand hours each year; and the obligation that the energy output from the resource be deliverable to load in PJM.

The most critical of these components of the definition of capacity is the obligation to offer the energy of the unit into the Day-Ahead Market. If buyers are to pay the high prices associated with RPM, it must be clear what they are buying and what the obligations of the sellers are. The fundamental energy market design should assure all market participants that the outcomes are competitive. This works to the ultimate advantage of all market participants including existing and prospective load and existing and prospective generation. The market rules should explicitly require that offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate.

An offer that exceeds short run marginal cost is not a competitive offer in the Day-Ahead Energy Market. Such an offer assumes the need to exercise market power to ensure revenue adequacy. An offer to provide energy only in an emergency is not a competitive offer in the Day-Ahead Energy Market. A unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis.

The obligation to offer energy in the Day-Ahead Energy Market should be applied without exception to all capacity resources, including both generation and demand resources. This means that capacity resources must be available every hour of the year at a competitive price. Demand resources that agree to interrupt only 10 days per year are not capacity resources. Generation resources that agree to provide an energy offer only under PJM emergency conditions are not capacity resources. Generation resources that agree to provide energy only when the price is extremely high (and greater than the short run marginal cost of such units) are not capacity resources. The only exception, and it is not really an exception, is that units which have a legitimate short term emergency condition, may appropriately offer the relevant portion of the unit as an emergency resource.

For the 2008/2009 Delivery Year, a daily average of approximately 2,700 MW (about 1.7 percent of all capacity cleared in RPM) of generation capacity were not offered into the energy market because they were designated as available only in a emergency.

Capacity resources are required to ensure the reliability of the system. Reliability is not defined as the operation of the system only during an emergency but the reliable operation of the system in every hour of the year. If the system reserve margin were comprised of demand resources that would only interrupt for 10 days or generation resources that would only perform during an emergency or generation that will only perform when the price is $999 per MWh, the probability of needing those resources would increase significantly and the number of hours during which those resources are needed would increase significantly. As a general matter, the probability of needing such resources increases with the level of such resources that are defined to be capacity and thus needed for reliability.

The actual dispatch of resources in the energy market should be a function of the marginal cost to produce energy for each resource and not based on the refusal of a resource to make a competitive offer. Net revenues from the energy market, the ancillary services markets and the capacity market are the market based compensation. Investment decisions result from this total compensation.

The sale of capacity is also the sale of recall rights to the energy from capacity resources during an emergency. Regardless of where the energy from a unit is sold, it must be recallable by PJM when PJM is in an emergency condition or a scarcity condition. PJM does not have clear protocols for recalling the energy output of capacity resources and has not recalled such energy since 1999, despite the fact that PJM has experienced emergency conditions since that time.

Capacity Prices and the Structure of Capacity Auctions

If capacity markets are to work to provide incentives for maintaining existing generation and building new generation, capacity market prices must reflect actual, local supply and demand conditions. For example, getting the price a little too low at the margin could result in undermining the incentives exactly where they need to be clear. If the prices are too low as a result of the market design, this would mean that the capacity market is a mechanism for transferring wealth rather than a functioning market providing market based incentives.

Capacity auctions must be mandatory for both load and generation, if they are to work. In PJM, load has a must bid requirement, which is enforced through the use of a system demand curve and the allocation of total capacity costs to all load. In PJM, capacity has a must offer requirement, which means that all capacity resources must offer into the capacity auctions unless they have a contract with an entity outside PJM or are physically unable to perform.[13]

The must bid and must offer requirements must extend to all resources. Thus, there should be no reduction of demand on the bid side. The current 2.5 percent reduction in the demand curve, to provide for short term resources, distorts the market price. The reduction in demand results in a price lower than the competitive level thus reducing the incentives to both new and existing generation. There should be no reductions in the demand for capacity, which should reflect all capacity needed to provide reliability.

The three year forward auction was implemented in order to provide the potential for new resources to compete with existing resources and to provide an incentive for such new entry. The prior capacity credit structure did not provide for either. The three year forward structure creates both opportunity and risks. A new generation unit that offers into an auction for a delivery year three years in the future is taking the risk that the unit will not be completed, that its costs will exceed its estimates or that the clearing price will be lower than anticipated in the first or subsequent years. Demand resources also face both opportunities and risks in a three year forward auction. A demand resource that is offered into an auction for a delivery year three years in the future is taking the risk that the customer with the demand side resource will no longer exist, that its costs will exceed its estimates or that the clearing price will be lower than anticipated in the first or subsequent years. There is nothing unique about demand resources that requires a shorter lead time or that requires distorting the market design. The fact that some generation resources or demand resources can be developed in less than three years is not a reason to distort the market design. It would be possible to shorten the time frame of the auctions for all participants but at the cost of reducing competition from new generation projects.

The must offer requirement for capacity should also apply generally to out of market transactions. Out of market transactions include the construction of new capacity by regulated utilities receiving out of market payments for such capacity via rate base treatment of the investment; by companies receiving out of market payments for such capacity via long term contracts; by companies receiving out of market payments for such capacity via Reliability Must Run (RMR) payments; and by companies receiving out of market payments for such capacity under renewable portfolio programs.

The market design goal is to ensure that out of market payments do not permit offers at less than competitive prices, including zero, which suppress the market clearing prices. All generation should be offered in to the auctions and receive capacity credit if cleared and not receive capacity credit if not cleared.

The must offer requirement should also extend to the elimination of the FRR exception to capacity markets.

Locational Prices

Capacity prices must reflect local supply and demand conditions. If capacity cannot be delivered into an area as a result of transmission constraints, a local market exists and capacity market prices

13 There is ongoing discussion in the PJM stakeholder process about exactly what the must offer provisions in the current tariff mean. The intent is clear and the tariff language should be conformed to the intent, which is that all capacity resources must make offers into each capacity auction.

should reflect the local market conditions. The CETO/CETL analysis currently used by PJM to define local markets in combination with consideration of local supply and demand is not adequate to define local markets in RPM. For example, if a unit does not clear in an RPM auction and makes an economic decision to retire but is then informed by PJM that it is needed for reliability, this is evidence that the market is not working because the local market is not properly defined. PJM determinations that a unit is needed for reliability are based on a more detailed analysis than the CETO/CETL analysis. PJM should perform such a more detailed reliability analysis of all at risk units, including all units that do not clear in RPM auctions and units that face significant investment requirements due, for example, to environmental requirements. If such units are needed for reliability, this could result in the definition of additional LDAs to reflect the actual reliability requirements of the system. Accurate locational pricing also requires that generation owners make offers that reflect their legitimate investment requirements. For example, units that will be forced to retire by environmental regulators unless they make defined investments in new technology should reflect the costs of that investment in their capacity market offer. That is essential to the functioning of the forward looking capacity market.

Capacity Markets and Incentives

If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, it would be preferable to also have a scarcity pricing mechanism in the energy market because it provides direct, hourly market-based incentives to load and generation, as long as it is designed to ensure that scarcity revenues directly offset RPM revenues. This hybrid approach would include both a capacity market and scarcity pricing in the energy market.

Capacity market design should reflect the fact that the capacity market is a mechanism for the collection of scarcity revenues and thus reflect the incentive structure of energy markets to the maximum extent possible. For example, if a generation unit does not produce power during a high price hour, it receives no revenues from the energy market. It does not receive some revenues simply for existing, it receives zero revenues. The reason that the unit does not produce energy is not relevant. It does not receive revenues if it does not produce energy even if the reason for non performance is outside management’s control. That is the basic performance incentive structure of energy markets. The same performance incentive structure should be replicated in capacity market design. If a unit that is a capacity resource does not produce energy during the 500 hours defined as critical in RPM, it will receive no energy revenues for those hours. If a unit defined as a capacity resource does not produce energy when called upon during any of the hours defined as critical, it should receive no capacity revenues. This approach to performance is also consistent with the reduction or elimination of administrative penalties associated with failure to meet capacity tests, for example.

A hybrid market design can provide scarcity revenues both via scarcity pricing in the energy market and via the capacity market. However, if there is scarcity pricing in the energy market, the market design must ensure that units receiving scarcity revenues in the capacity market do not also receive scarcity revenues in the energy market. This would be double payment of scarcity revenues. This offset must reflect the actual scarcity revenues and not those reflected in forward curves or forecasts, or those reflected in results from prior years. Scarcity revenues are episodic and unlikely to be fully reflected in historical data or in forward curves, even if such curves were based on a liquid market three years forward, which they are not, and reflected locational results, which they do not. The most straightforward way to ensure that such double payment does not occur would be to ensure that capacity resources do not receive scarcity revenues in the energy market in the first place. The settlements process can remove any scarcity revenues from payments to capacity resources and eliminate the need for a complex, uncertain, after the fact procedure for offsetting scarcity revenues in the capacity market.

Market Power

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. 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 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.

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 by limiting the exercise of market power via the application of the three pivotal supplier test.

Competitive prices are the lowest possible prices, consistent with the resource costs. But, competitive prices are not necessarily low prices. In the Capacity Market, it is essential that the cost of new entry (CONE) be based on the actual resource costs of bringing a new capacity resource into service. If RPM is to provide appropriate incentives for new entry, the marginal price signal must reflect the actual cost of new entry.

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. The performance incentives in the RPM Capacity Market design need to be strengthened. 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.

Results

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 examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The MMU found serious market structure issues, measured by the three pivotal supplier test results, by market shares and by HHI, but no exercise of market power in the PJM Capacity Market during calendar year 2009. 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 calendar year 2009.

RPM Capacity Market

Market Design

The RPM Capacity Market, implemented June 1, 2007 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.

Annual base auctions are held in May for delivery years that are three years in the future. Prior to January 22, 2010, First, Second and Third Incremental RPM Auctions were conducted 23, 13 and four months prior to the delivery year. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[14] In 2009, the 2012/2013 BRA was held in May.[15] A Third Incremental Auction was held in January 2009 for the delivery year 2009/2010, and a First Incremental Auction was held in June for the delivery year 2011/2012.[16]

14 Letter Order in Docket No. ER10-366-000 (January 22, 2010).

15 Delivery years are from June 1 through May 31. The 2009/2010 delivery year runs from June 1, 2009, through May 31, 2010.

16 For more detailed analysis of the 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 2008/2009 Third Incremental RPM Auction" (June 23, 2008); "Analysis of the 2009/2010 RPM Auction" (November 30, 2007); "Analysis of the 2010/2011 RPM Auction" (May 6, 2008); "Analysis of the 2011/2012 RPM Auction" (September 12, 2008); "Analysis of the 2012/2013 RPM Base Residual Auction" (August 6, 2009) <http://www.monitoringanalytics.com/reports/Reports.shtml>.

Market Structure

Supply

As shown in Table 5-1, total internal capacity increased 350.2 MW from 156,968.0 MW on June 1, 2008, to 157,318.2 MW on June 1, 2009. This increase was the result of 439.2 MW of new generation, and 74.1 MW from generation uprates. DR offers increased 220.6 MW. The net EFORd effect was -383.7 MW. The EFORd effect is the measure of the net internal capacity change attributable to EFORd changes and not capacity modifications.

In the 2010/2011, 2011/2012, and 2012/2013 auctions, new generation increased 3,271.9 MW; 651.9 MW came out of retirement and net generation deratings were 2,994.9 MW, for a total of 928.9 MW. DR and Energy Efficiency (EE) offers increased 9,409.3 MW through June 1, 2012. A decrease of 890.3 MW was due to higher EFORds. The reclassification of the Duquesne resources as internal added 3,187.2 MW to total internal capacity. The net effect from June 1, 2009, through June 1, 2012, was an increase in total internal capacity of 12,635.1 MW (8.0 percent) from 157,318.2 MW to 169,953.3 MW.

As also shown in Table 5-1 and Table 5-7, in the 2009/2010 RPM Auction, the increase of 17 RPM generation resources consisted of 11 new resources (439.2 MW), nine resources that were previously entirely FRR committed (82.5 MW), two less resources exported (698.6 MW), and two fewer resources excused from offering into the auction (37.3 MW) offset by five excused resources (44.5 MW), one less external resource that did not offer (60.4 MW), and one additional resource committed fully to FRR (10.0 MW). The new resources consisted of eight new CT resources (380.2 MW), two new diesel resources (9.2 MW) and one new steam resource (49.8 MW). There were 38 DR resources offered compared to 23 DR resources offered in the 2008/2009 RPM Auction.

As shown in Table 5-1 and Table 5-8, in the 2010/2011 auction, the increase of 11 RPM generation resources consisted of 15 new resources (406.9 MW), four reactivated resources (161.7 MW), three that were previously entirely FRR committed (10.9 MW), one less resource excused from offering (3.9 MW), and one less resource entirely exported (39.9 MW), offset by four deactivated resources (59.6 MW), four resources exported from PJM (554.0 MW), three retired resources (348.4 MW), and two resources excused from offering (108.8 MW). The new resources consisted of seven CT resources (270.5 MW), five new wind resources (120.0 MW), three new diesel resources (16.4 MW), and four reactivated resources (165.0 MW). There were 23 demand resources (DR) offered compared to 38 DR resources offered in the 2009/2010 RPM auction.

As also shown in Table 5-1 and Table 5-8, in the 2011/2012 auction, the increase of 21 generation resources consisted of 20 new resources (2,203.7 MW), four reactivated resources (486.9 MW), three fewer excused resources (126.3 MW), and one additional resource imported (663.2 MW), offset by five additional resources committed fully to FRR (1.0 MW) and two retired resources (87.3 MW). The new resources consisted of 11 new CT resources (728.7 MW), four new wind resources (75.2 MW), two new steam resources (838.0 MW), one new combined cycle resource (556.5 MW), one new diesel resource (4.2 MW) and one new solar resource (1.1 MW). There were 37 demand resources (DR) offered compared to 23 DR resources offered in the 2010/2011 RPM auction.

As shown in Table 5-1 and Table 5-8, in the 2012/2013 auction, the increase of eight generation resources consisted of 16 new resources (772.5 MW), four resources that were previously entirely FRR committed (13.4 MW), three additional resources imported (276.8 MW), two additional resources resulting from disaggregation of RPM resources, and one resource formerly unoffered (1.9 MW), offset by nine retired resources (1,044.5 MW), four additional resources committed fully to FRR (39.5 MW), four less resources resulting from aggregation of RPM resources, and one less external resource that did not offer (663.2 MW).[17] In addition, there were the following retirements of resources that were either exported or excused in the 2011/2012 BRA: two combustion turbine resources (5.3 MW) and three combined cycle resources (297.6 MW). Also, resources that are no longer PJM capacity resources consisted of three CT units (521.5 MW) in the RTO. The new resources consisted of six new diesel resources (13.9 MW), four new wind resources (57.9 MW), three new steam units (560.4 MW), and three new CT units (140.3 MW). There were 233 demand resources (DR) offered compared to 37 DR resources offered in the 2011/2012 RPM Base Residual Auction. There were 53 Energy Efficiency (EE) resources offered as a new resource type for the 2012/2013 planning year.

17 Disaggregation and aggregation of RPM resources reflect changes in how units are offered in RPM. For example, multiple units at a plant may be offered as a single unit or multiple units.

Table 5-1 Internal capacity: June 1, 2008, through May 31, 2012[18,19]

	UCAP (MW)						
	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL South	PSEG North
Total internal capacity @ 01-Jun-08	156,968.0	72,889.5			10,777.1		
New generation	439.2	109.9			0.0		
Units out of retirement	0.0	0.0			0.0		
Generation capmods	74.1	(149.7)			(298.2)		
DR mods	220.6	163.2			42.3		
Net EFORd effect	(383.7)	0.0			(176.0)		
Total internal capacity @ 01-Jun-09	157,318.2	73,012.9			10,345.2	1,587.0	
New generation	406.9					0.0	
Units out of retirement	165.0					0.0	
Generation capmods	1,085.8					(85.5)	
DR mods	43.7					15.7	
Net EFORd effect	11.3					28.9	
Total internal capacity @ 01-Jun-10	159,030.9					1,546.1	
New generation	2,203.7						
Units out of retirement	486.9						
Generation capmods	(2,567.6)						
DR mods	684.4						
Net EFORd effect	44.4						
Total internal capacity @ 01-Jun-11	159,882.7		66,329.7	32,733.0		1,460.3	4,167.5
Reclassification of Duquesne resources	3,187.2		0.0	0.0		0.0	0.0
Adjusted internal capacity @ 01-Jun-11	163,069.9		66,329.7	32,733.0		1,460.3	4,167.5
New generation	661.3		61.9	59.7		0.0	0.0
Units out of retirement	0.0		0.0	0.0		0.0	0.0
Generation capmods	(1,513.1)		(901.3)	(444.9)		(31.8)	(509.0)
DR mods	8,028.7		3,829.7	1,480.9		64.6	67.6
EE mods	652.5		186.9	24.4		0.0	0.9
Net EFORd effect	(946.0)		(503.0)	(185.6)		5.8	18.3
Total internal capacity @ 01-Jun-12	169,953.3		69,003.9	33,667.5		1,498.9	3,745.3

18 The RTO includes MAAC+APS, EMAAC and SWMAAC. MAAC+APS and MAAC include EMAAC and SWMAAC. EMAAC includes DPL South and PSEG North. Results for only constrained LDAs are shown. Maps of the LDAs can be found in the *2009 State of the Market Report for PJM*, Appendix A, "PJM Geography."

19 The UCAP MW value attributed to the reclassification of Duquesne units differs from the value reported in the *2008 State of the Market Report for PJM* as a result of generation cap mods, DR and EE mods, and EFORd changes.

Demand

There was a 2,545.5 MW increase in the RPM reliability requirement from 150,934.6 MW on June 1, 2008, to 153,480.1 MW on June 1, 2009. This increase resulted from a higher peak-load forecast.

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.

On June 1, 2009, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 79.6 percent (Table 5-2), down slightly from 80.1 percent on June 1, 2008. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 20.4 percent, up from 19.9 percent on June 1, 2008. Obligation is defined as cleared MW plus ILR forecast obligations.

Table 5-2 PJM Capacity Market load obligation served: June 1, 2009

	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	68,587.1	11,994.4	26,027.0	1,056.0	10,452.7	517.3	15,252.5	133,887.0
Percent of total obligation	51.2%	9.0%	19.4%	0.8%	7.8%	0.4%	11.4%	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 Base Residual Auctions.[20] The results of the PMSS are applicable for the First, Second, and Third Incremental Auctions for a given delivery year.[21] 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.[22]

As shown in Table 5-3, 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.[23]

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

21 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," Second Revised Sheet No. 593 (Effective November 1, 2009), section 5.11 (b).

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

23 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," First Revised Sheet No. 610 (Effective November 1, 2009), section 6.7 (b).

Table 5-3 Preliminary market structure screen results: 2009/2010 through 2012/2013 RPM Auctions

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
2009/2010				
RTO	18.4%	853	1	Fail
SWMAAC	51.1%	4229	1	Fail
MAAC+APS	26.9%	1627	1	Fail
2010/2011				
RTO	18.4%	853	1	Fail
EMAAC	31.3%	2053	1	Fail
SWMAAC	51.1%	4229	1	Fail
MAAC+APS	26.9%	1627	1	Fail
2011/2012				
RTO	18.0%	855	1	Fail
2012/2013				
RTO	17.4%	853	1	Fail
MAAC	17.6%	1071	1	Fail
EMAAC	32.8%	2057	1	Fail
SWMAAC	50.7%	4338	1	Fail
PSEG	84.3%	7188	1	Fail
PSEG North	90.9%	8287	1	Fail
DPL South	55.0%	3828	1	Fail

Auction Market Structure

As shown in Table 5-4, all participants in the total PJM market as well as the LDA RPM markets failed the TPS test in the 2009/2010 BRA, the 2009/2010 Third Incremental Auction, the 2010/2011 BRA, the 2011/2012 BRA, and the 2011/2012 First IA.[24] The result was that offer caps were applied to all sell offers. In the 2012/2013 BRA, all participants included in the incremental supply of EMAAC passed the test. The result was that offer caps were applied to all sell offers of participants that did not pass the test, excluding sell offers for new units. In applying the market structure test, the relevant supply for the RTO market includes all offers less than or equal to 150% of the cost-based clearing price, and the relevant demand includes cleared MW at or below the unconstrained clearing price. The constrained LDA markets include the incremental supply inside the constrained LDAs which was offered at a price higher than 150% of the unconstrained clearing price for the parent LDA market. The incremental demand consists of the MW needed inside the LDA to relieve the constraint.

24 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See the *2009 State of the Market Report for PJM*, Appendix L, "Three Pivotal Supplier Test" for additional discussion.

Table 5-4 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the Residual Supply Index (RSI_x). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

Table 5-4 RSI results: 2009/2010 through 2012/2013 RPM Auctions[25]

RPM Markets	RSI_3	Total Participants	Failed RSI_3 Participants
2009/2010 BRA			
RTO	0.60	66	66
MAAC+APS	0.37	21	21
SWMAAC	0.00	3	3
2009/2010 Third IA			
RTO	0.64	40	40
MAAC+APS	0.14	8	8
2010/2011 BRA			
RTO	0.60	68	68
DPL South	0.00	2	2
2011/2012 BRA			
RTO	0.63	76	76
2011/2012 First IA			
RTO	0.62	30	30
2012/2013 BRA			
RTO	0.63	98	98
MAAC/SWMAAC	0.54	15	15
EMAAC/PSEG	7.03	6	0
PSEG North	0.00	2	2
DPL South	0.00	3	3

25 The RSI shown is the lowest RSI in the market.

Imports and Exports

As shown in Table 5-5, net exchange increased 1,688.3 MW from June 1, 2008 to June 1, 2009. Net exchange, which is imports less exports, increased due to a decrease in exports of 1,643.2 MW and an increase in imports of 45.1 MW.

Table 5-5 PJM capacity summary (MW): June 1, 2007 through May 31, 2012[26,27]

	01-Jun-07	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11	01-Jun-12
Installed capacity (ICAP)	163,721.1	164,444.1	166,916.0	168,061.5	172,666.6	181,159.7
Unforced capacity	154,076.7	155,590.2	157,628.7	158,634.2	163,144.3	171,147.8
Cleared capacity	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5
RPM reliability requirement (pre-FRR)	148,277.3	150,934.6	153,480.1	156,636.8	154,251.1	157,488.5
RPM reliability requirement (less FRR)	125,805.0	128,194.6	130,447.8	132,698.8	130,658.7	133,732.4
RPM net excess	5,240.5	5,011.1	8,265.5	1,149.2	3,156.6	5,754.4
Imports	2,809.2	2,460.3	2,505.4	2,750.7	6,420.0	3,831.6
Exports	(3,938.5)	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)	(2,637.1)
Net exchange	(1,129.3)	(1,377.8)	310.5	(396.7)	3,261.6	1,194.5
DR cleared	127.6	536.2	892.9	939.0	1,364.9	7,047.2
EE cleared						568.9
ILR	1,636.3	3,608.1	6,481.5	2,110.5	1,593.8	
FRR DR	445.6	452.8	423.6	452.9	452.9	488.1
Short-Term Resource Procurement Target						3,343.3

Demand-Side Resources

Under the PJM load management (LM) program, qualifying load management resources can be offered into RPM Auctions as capacity resources and receive the clearing price, or, prior to the 2012/2013 delivery year, 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 clearing price. ILR resources are load resources 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 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 Residual Auction for the delivery year but at least three months prior to the delivery year during

26 FRR DR values have been revised since the *2008 State of the Market Report for PJM* was posted.

27 Prior to the 2012/2013 delivery year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For 2008/2009 and 2009/2010, certified ILR was used in the calculation. For 2010/2011, forecast ILR less FRR DR is used in the calculation because PJM forecast ILR including FRR DR for the first four base residual auctions. FRR DR is not subtracted in the calculation for the 2011/2012 auction, because PJM forecast ILR excluding FRR DR for the 2011/2012 BRA. Net excess calculations for auctions prior to 2010/2011 were originally calculated as cleared capacity less the reliability requirement. For delivery years 2012/2013 and beyond, net excess under RPM is calculated as cleared capacity less the reliability requirement plus the Short-Term Resource Procurement Target.

which they will participate. Beginning with the 2012/2013 delivery year, the load management product ILR was eliminated. It was replaced by the Short-Term Resource Procurement Target.

The Energy Efficiency (EE) resource type is eligible to be offered in RPM auctions starting with the 2012/2013 delivery year and also for incremental auctions in the 2011/2012 delivery year.[28] An EE Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak periods) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such delivery year, without any requirement of notice, dispatch, or operator intervention.[29]

As shown in Table 5-6, capacity in the RPM load management programs, which prior to the 2012/2013 delivery year is a combination of DR cleared in the RPM Auctions and certified/forecast ILR, increased by 3,206.9 MW from 4,167.5 MW on June 1, 2008 to 7,374.4 MW on June 1, 2009. Final ILR is certified three months before the delivery year and it may differ from the ILR forecast.

Table 5-6 RPM load management statistics: June 1, 2008 through May 31, 2012[30]

	UCAP (MW)						
	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL South	PSEG North
DR cleared	559.4			169.0	309.2		
ILR certified	3,608.1			622.6	219.7		
RPM load management @ 01-June-2008	4,167.5			791.6	528.9		
DR cleared	892.9	813.9			356.3		
ILR certified	6,481.5	1,055.7			345.7		
RPM load management @ 01-June-2009	7,374.4	1,869.6			702.0		
DR cleared	939.0					14.9	
ILR forecast - FRR DR	1,657.6					22.2	
RPM load management @ 01-June-2010	2,596.6					37.1	
DR cleared	1,364.9						
ILR forecast	1,593.8						
RPM load management @ 01-June-2011	2,958.7						
DR cleared	7,047.2		4,723.7	1,638.4		64.6	67.6
EE cleared	568.9		179.9	20.0		0.0	0.9
RPM load management @ 01-June-2012	7,616.1		4,903.6			64.6	68.5

28 Letter Order in Docket No. ER10-366-000 (January 22, 2010).

29 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," First Revised Sheet No. 35C (Effective March 27, 2009), Section M.

30 PJM used forecast ILR, including FRR DR, for the first four base residual auctions. For 2008/2009 and 2009/2010, certified ILR data were used in the calculation here because the certified ILR data are now available. For 2010/2011, forecast ILR less FRR DR is used and will continue to be used until certified ILR data are available. PJM used forecast ILR, excluding FRR DR, for the 2011/2012 BRA. Therefore, FRR DR is not subtracted in the calculation here for the 2011/2012 auction. Effective the 2012/2013 delivery year, ILR was eliminated and the Energy Efficiency (EE) resource type was eligible to be offered in RPM auctions.

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.[31] 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.[32]

31 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," First Revised Sheet No. 617 (Effective January 19, 2008), section 6.8 (b).

32 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.

Table 5-7 ACR statistics: 2009/2010 RPM Auctions

	2009/2010 BRA		2009/2010 Third IA	
Calculation Type	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered
Default ACR selected	377	34.5%	1	0.4%
ACR data input (non-APIR)	22	2.0%	0	0.0%
ACR data input (APIR)	129	11.8%	2	0.7%
Opportunity cost input	10	0.9%	2	0.7%
Transition adder only	12	1.1%	0	0.0%
Offer caps calculated	550	50.3%	5	1.9%
Uncapped new units	3	0.3%	6	2.2%
Generators capped at 1.1 times BRA clearing price	NA		255	95.5%
Generator price takers	540	49.4%	1	0.4%
Generating units offered	1,093	100.0%	267	100.0%
Demand resources offered	38		13	
Total capacity resources offered	1,131		280	

Table 5-8 ACR statistics: 2010/2011 through 2012/2013 RPM Auctions

	2010/2011 BRA		2011/2012 BRA		2011/2012 First IA		2012/2013 BRA	
Calculation Type	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered
Default ACR selected	370	33.5%	301	26.8%	47	36.4%	476	42.0%
ACR data input (non-APIR)	20	1.8%	12	1.1%	18	14.0%	118	10.4%
ACR data input (APIR)	134	12.1%	133	11.8%	1	0.8%	2	0.2%
Opportunity cost input	8	0.7%	24	2.1%	2	1.6%	8	0.7%
Default ACR and opportunity cost input	0	0.0%	2	0.2%	0	0.0%	3	0.3%
Offer caps calculated	532	48.1%	472	42.0%	68	52.8%	607	53.6%
Uncapped new units	15	1.4%	20	1.8%	1	0.8%	11	1.0%
Generator price takers	557	50.5%	633	56.2%	60	46.4%	515	45.4%
Generating units offered	1,104	100.0%	1,125	100.0%	129	100.0%	1,133	100.0%
Demand resources offered	23		37		0		233	
Energy efficiency resources offered	0		0		0		53	
Total capacity resources offered	1,127		1,162		129		1,419	

Table 5-9 APIR statistics: 2009/2010 through 2012/2013 RPM Auctions[33,34,35]

		Weighted-Average ($ per MW-day UCAP)						
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	SubCritical/ SuperCritical Coal	Other	Opportunity Costs	Total
2009/2010 BRA								
Non-APIR units	ACR	$37.74	$26.07	$80.09	$159.26	$84.07		$82.66
	Net revenues	$61.97	$23.08	$31.92	$321.88	$516.72		$162.48
	Offer caps	$14.76	$13.51	$49.81	$11.44	$1.36	$123.60	$26.32
APIR units	ACR	$58.12	$43.83	$129.59	$525.98	$30.71		$285.17
	Net revenues	$97.94	$16.10	$19.71	$322.91	$15.75		$172.57
	Offer caps	$17.93	$30.45	$109.88	$164.31	$22.45		$102.07
	APIR	$0.24	$22.86	$43.79	$386.13	$18.96		$195.85
	Maximum APIR effect							$383.79
2010/2011 BRA								
Non-APIR units	ACR	$34.39	$27.10	$67.57	$167.08	$82.55		$80.86
	Net revenues	$96.75	$18.81	$15.19	$302.79	$391.00		$151.31
	Offer caps	$10.13	$14.12	$52.38	$9.67	$4.53	$124.60	$20.98
APIR units	ACR	$61.61	$49.26	$152.09	$654.18	$34.62		$360.27
	Net revenues	$26.84	$10.32	$20.94	$525.48	$2.07		$263.27
	Offer caps	$37.30	$39.41	$131.15	$155.39	$32.55		$110.25
	APIR	$9.87	$30.93	$60.54	$521.16	$22.42		$272.18
	Maximum APIR effect							$577.03
2011/2012 BRA								
Non-APIR units	ACR	$39.52	$30.17	$72.20	$181.52	$62.54		$75.86
	Net revenues	$69.04	$20.16	$17.27	$466.41	$322.78		$173.54
	Offer caps	$11.76	$16.42	$62.13	$7.88	$11.50	$182.41	$45.80
APIR units	ACR	$61.66	$56.28	$184.34	$723.65	$36.03		$424.49
	Net revenues	$78.17	$10.35	$19.81	$531.93	$2.06		$286.80
	Offer caps	$34.69	$46.18	$164.54	$203.41	$33.97		$147.77
	APIR	$11.82	$37.28	$91.30	$578.47	$24.68		$324.58
	Maximum APIR effect							$523.26
2011/2012 First IA								
Non-APIR units	ACR	$54.15	$29.43	$71.79	$284.63	$30.04		$169.77
	Net revenues	$220.31	$44.98	$10.25	$298.96	$0.07		$195.83
	Offer caps	$2.66	$2.64	$61.54	$150.63	$29.97	$136.01	$78.56
APIR units	ACR	$220.20	$152.28	$194.25	$583.59			$326.57
	Net revenues	$81.72	$6.94	$23.64	$328.71			$128.90
	Offer caps	$138.48	$145.34	$170.62	$254.88			$197.67
	APIR	$220.19	$120.84	$82.87	$324.31			$170.61
	Maximum APIR effect							$468.26
2012/2013 BRA								
Non-APIR units	ACR	$41.84	$32.61	$75.47	$207.54	$57.18		$110.84
	Net revenues	$91.67	$35.29	$7.51	$396.82	$257.96		$208.65
	Offer caps	$5.28	$14.40	$67.96	$11.31	$15.63	$136.48	$21.55
APIR units	ACR	$218.10	$49.83	$177.52	$715.10	NA		$464.65
	Net revenues	$98.97	$15.62	$3.62	$508.00	NA		$302.04
	Offer caps	$119.12	$34.96	$173.89	$215.38	NA		$167.62
	APIR	$218.10	$26.59	$89.08	$559.97	NA		$351.74
	Maximum APIR effect							$1,155.57

33 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.

34 This table has been updated since the MMU RPM Auction reports were posted. The 2010/2011 and 2011/2012 BRA values for Oil and Gas Steam and Sub Critical/Super Critical Coal for resources with an APIR component were updated due to a prior misclassification.

35 Statistics for the 2009/2010 Third IA are not included as 95.5 percent of the resources chose the offer cap option of 1.1 times the BRA clearing price.

2009/2010 RPM Base Residual Auction

As shown in Table 5-7, 1,093 generating resources submitted offers in the 2009/2010 RPM Auction as compared to 1,076 generating resources offered in the 2008/2009 RPM Auction. Unit-specific offer caps were calculated for 151 resources (13.8 percent). Offer caps of all kinds were calculated for 550 resources (50.3 percent), of which 377 were based on the technology specific default (proxy) ACR posted by the MMU. Three new generation resources had uncapped offers while the remaining 540 generation resources were price takers, of which the offers for 514 resources were zero and the offers for 26 resources were set to zero because no data were submitted.[36] The transition adder was part of the offers on 206 resources, of which offers on 12 resources included only the transition adder. The transition adder had no impact on the clearing prices.

Of the 1,093 generating resources which submitted offers, 129 (11.8 percent) included an APIR component. (See Table 5-7.) As shown in Table 5-9, the weighted-averages for resources with APIR for ACR ($285.17 per MW-day) and offer caps ($102.07 per MW-day) were higher than the ACR ($82.66 per MW-day) and offer caps ($26.32 per MW-day) for resources without an APIR component, including resources for which the default value was selected. The APIR component added $195.85 per MW-day to the ACR value of the APIR resources.[37] The default ACR values include an average APIR of $0.91 per MW-day. The highest APIR for a technology ($386.13 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($383.79 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2009/2010 RPM Third Incremental Auction

As shown in Table 5-7, 267 generating resources submitted offers in the 2009/2010 RPM Third Incremental Auction. Unit-specific offer caps were calculated for two resources (0.7 percent). Offer caps of all kinds were calculated for five resources (1.9 percent), of which one was based on the technology specific default (proxy) ACR posted by the MMU. 255 generation resources (95.6 percent) chose the option of 1.1 times the BRA clearing price as an offer cap, of which 160 resources submitted nonzero sell offers. Of the 267 generating units, the remaining six (2.2 percent) resources were uncapped new units while one (0.4 percent) resource did not elect the 1.1 times the BRA clearing price offer cap option.

2010/2011 RPM Base Residual Auction

As shown in Table 5-8, 1,104 generating resources submitted offers in the 2010/2011 RPM Auction as compared to 1,093 generating resources offered in the 2009/2010 RPM Auction. Unit-specific offer caps were calculated for 154 resources (13.9 percent) including 134 resources (12.1 percent) with an APIR component and 20 resources (1.8 percent) without an APIR component. Offer caps of all kinds were calculated for 532 resources (48.1 percent), of which 370 (33.5 percent) were based on the technology specific default (proxy) ACR posted by the MMU. There were 15 new generation resources with uncapped offers while the remaining 557 generation resources were price takers,

36 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," Substitute Second Revised Sheet No. 607 (Effective March 27, 2009), section 6.5 (a) ii.

37 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 on the inclusion of 2007/2008 and 2008/2009 capital projects.

of which the offers for 546 resources were zero and the offers for 11 resources were set to zero because no data were submitted.[38]

Of the 1,104 generating resources which submitted offers, 134 (12.1 percent) included an APIR component. (See Table 5-8.) As shown in Table 5-9, the weighted-averages for resources with APIR for ACR ($360.27 per MW-day) and offer caps ($110.25 per MW-day) were higher than the ACR ($80.86 per MW-day) and offer caps ($20.98 per MW-day) for resources without an APIR component, including resources for which the default value was selected. The APIR component added $272.18 per MW-day to the ACR value of the APIR resources.[39] The default ACR values include an average APIR of $0.91 per MW-day. The highest APIR for a technology ($521.16 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($577.03 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2011/2012 RPM Base Residual Auction

As shown in Table 5-8, 1,125 generating resources submitted offers in the 2011/2012 RPM Auction as compared to 1,104 generating resources offered in the 2010/2011 RPM Auction. Unit-specific offer caps were calculated for 145 resources (12.9 percent of all generating resources offered) including 133 resources (11.8 percent) with an APIR component and 12 resources (1.1 percent) without an APIR component. Offer caps of all kinds were calculated for 472 resources (42.0 percent), of which 301 (26.8 percent) were based on the technology specific default (proxy) ACR posted by the MMU. There were 20 new generation resources with uncapped offers while the remaining 633 generation resources were price takers, of which the offers for 578 resources were zero and the offers for 55 resources were set to zero because no data were submitted.[40]

Of the 1,125 generating resources which submitted offers, 133 (11.8 percent) included an APIR component. (See Table 5-8.) As shown in Table 5-9, the weighted-averages for resources with APIR for ACR ($424.49 per MW-day) and offer caps ($147.77 per MW-day) were higher than the ACR ($75.86 per MW-day) and offer caps ($45.80 per MW-day) for resources without an APIR component, including resources for which the defaults ACR value was selected. The APIR component added $324.58 per MW-day to the ACR value of the APIR resources.[41] The default ACR values include an average APIR of $0.91 per MW-day. The highest APIR for a technology ($578.47 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($523.26 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2012/2013 RPM Base Residual Auction

As shown in Table 5-8, 1,133 generating resources submitted offers in the 2012/2013 RPM Auction as compared to 1,125 generating resources offered in the 2011/2012 RPM Auction. Unit-specific offer caps were calculated for 120 resources (10.6 percent of all generating resources offered) including 118 resources (10.4 percent) with an APIR component and 2 resources (0.2 percent) without an APIR component. Offer caps of all kinds were calculated for 607 resources (53.6 percent),

38 Planned units are subject to mitigation only under specific circumstances defined in the tariff. Some of the uncapped planned units submitted zero price offers.
39 The 134 units which had an APIR component submitted $1.5 billion for capital projects associated with 12,645.3 MW UCAP.
40 Planned units are subject to mitigation only under specific circumstances defined in the tariff. Some of the 20 uncapped planned units submitted zero price offers.
41 The 133 units which had an APIR component submitted $613.8 million for capital projects associated with 8,813.7 MW UCAP.

of which 476 (42.0 percent) were based on the technology specific default (proxy) ACR posted by the MMU. There were 11 new generation resources with uncapped offers while the remaining 515 generation resources were price takers, of which the offers for 512 resources were zero and the offers for three resources were set to zero because no data were submitted.[42]

Of the 1,133 generating resources which submitted offers, 118 (10.4 percent) included an APIR component. (See Table 5-8.) As shown in Table 5-9, the weighted-averages for resources with APIR for ACR ($464.65 per MW-day) and offer caps ($167.62 per MW-day) were higher than the ACR ($110.84 per MW-day) and offer caps ($21.55 per MW-day) for resources without an APIR component, including resources for which the defaults ACR value was selected. The APIR component added $351.74 per MW-day to the ACR value of the APIR resources.[43] The default ACR values include an average APIR of $1.31 per MW-day. The highest APIR for a technology ($559.97 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($1,155.57 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

Market Performance

Prices for capacity decreased from $111.92 per MW-day for the RTO for the 2008/2009 BRA to $102.04 per MW-day for the 2009/2010 BRA. (See Table 5-10.)

Annual weighted average capacity prices increased from a CCM/RPM combined, weighted average price of $5.73 per MW-day in 2006 to an RPM weighted-average price of $173.15 per MW-day in 2010 and then declined to $90.08 per MW-day in 2012. Figure 5-1 presents capacity market prices on a calendar year basis for the entire history of the PJM capacity markets.

As Table 5-5 shows, net excess increased 3,254.4 MW from 5,011.1 MW on June 1, 2008, to 8,265.5 MW on June 1, 2009, because of a 2,873.4 MW increase in ILR and a 2,634.2 MW increase in cleared capacity, offset by an increase in the reliability requirement of 2,253.2 MW.[44] The increase in unforced capacity of 2,038.5 MW was the result of a decrease in exports of 1,643.2 MW, a 350.2 MW growth in total internal capacity, plus an increase in imports of 45.1 MW.[45] (See Table 5-5.)

42 Planned units are subject to mitigation only under specific circumstances defined in the tariff. Some of the 11 uncapped planned units submitted zero price offers.

43 The 118 units which had an APIR component submitted $567.2 million for capital projects associated with 11,124.8 MW of UCAP.

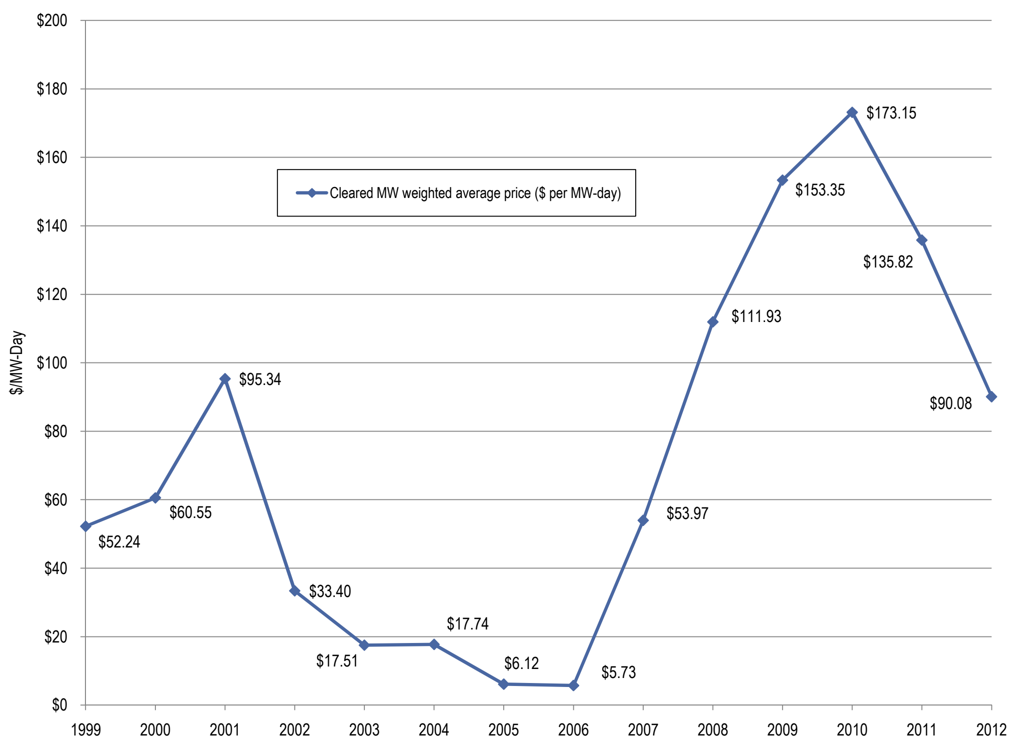
44 Prior to the 2012/2013 delivery year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For 2008/2009 and 2009/2010, certified ILR was used in the calculation. For 2010/2011, forecast ILR less FRR DR is used in the calculation because PJM forecast ILR including FRR DR for the first four base residual auctions. FRR DR is not subtracted in the calculation for the 2011/2012 auction, because PJM forecast ILR excluding FRR DR for the 2011/2012 BRA. Net excess calculations for auctions prior to 2010/2011 were originally calculated as cleared capacity less the reliability requirement. For delivery years 2012/2013 and beyond, net excess under RPM is calculated as cleared capacity less the reliability requirement plus the Short-Term Resource Procurement Target.

45 Unforced capacity is defined as the UCAP value of iron in the ground plus the UCAP value of imports less the UCAP value of exports.

Table 5-10 Capacity prices: 2007/2008 through 2012/2013 RPM Auctions

	RPM Clearing Price ($ per MW-day)						
	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL South	PSEG North
2007/2008 BRA	$40.80			$197.67	$188.54		
2008/2009 BRA	$111.92			$148.80	$210.11		
2008/2009 Third IA	$10.00				$223.85		
2009/2010 BRA	$102.04	$191.32			$237.33		
2009/2010 Third IA	$40.00	$86.00					
2010/2011 BRA	$174.29					$178.27	
2011/2012 BRA	$110.00						
2011/2012 First IA	$55.00						
2012/2013 BRA	$16.46		$133.37	$139.73		$222.30	$185.00

Figure 5-1 History of capacity prices: Calendar year 1999 through 2012[46]



46 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2012 capacity prices are RPM weighted average prices.

Table 5-11 RPM cost to load: 2009/2010 through 2012/2013 RPM Auctions[47,48,49]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2009/2010 BRA			
RTO	$104.82	56,696.9	$2,169,117,837
MAAC+APS	$193.78	60,984.3	$4,313,445,473
SWMAAC	$224.86	16,205.7	$1,330,043,812
2010/2011 BRA			
RTO	$174.29	129,340.6	$8,228,112,710
DPL	$178.27	4,507.5	$293,295,977
2011/2012 BRA			
RTO	$110.04	133,815.3	$5,389,363,034
2012/2013 BRA			
RTO	$16.46	69,648.3	$418,440,022
MAAC	$129.63	31,338.7	$1,482,789,024
EMAAC	$135.18	21,171.5	$1,044,616,630
DPL	$162.99	4,685.6	$278,752,670
PSEG	$149.65	12,642.7	$690,572,720

Table 5-11 shows the RPM annual charges to load. For the 2009/2010 planning year, annual charges totaled approximately $7.8 billion.

2009/2010 RPM Base Residual Auction

Cleared capacity resources across the entire RTO will receive a total of $7.5 billion based on the unforced MW cleared and the prices in the 2009/2010 BRA.

RTO

Table 5-12 shows total RTO offer data for the 2009/2010 RPM Auction, which includes the MAAC+APS and SWMAAC LDAs. Total internal RTO unforced capacity of 157,318.2 MW includes all generating units and DR that qualified as a PJM capacity resource for the 2009/2010 RPM

47 The annual charges are calculated using the rounded, net load prices as posted in the PJM Base Residual Auction results.

48 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone.

49 Prior to the 2009/2010 delivery year, the Final UCAP Obligation is determined after the clearing of the Second IA. For the 2009/2010 through 2011/2012 delivery years, the Final UCAP Obligations are determined after the clearing of the Third IA. Effective with the 2012/2013 delivery year, the Final UCAP Obligation is determined after the clearing of the final incremental auction. Prior to the 2012/2013 delivery year, the Final Zonal Capacity Prices are determined after certification of ILR. Effective with the 2012/2013 delivery year, the Final Zonal Capacity Prices are determined after the final incremental auction. The 2010/2011 Net Load Prices are not finalized. The 2011/2012 and 2012/2013 Net Load Prices and Obligation MW are not finalized.

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.[50]

After accounting for FRR committed resources and for imports, RPM capacity was 136,300.4 MW.[51] This amount was reduced by exports of 2,194.9 MW[52] and 104.3 MW which were excused from the RPM must-offer requirement as a result of non-utility generator (NUG) ownership questions (57.2 MW), planned reductions due to environmental regulations (33.5 MW), planned capacity withdrawals (5.5 MW), generation moving behind the meter (4.0 MW) and other factors (4.1 MW). Subtracting 450.2 MW of FRR optional volumes not offered, resulted in 133,551.0 MW that were available to be offered into the auction.[53] Offered volumes included 1,151.3 MW of EFORd offer segments. All capacity resources were offered into the RPM Auction. Eight new CT units (380.2 MW), one new diesel unit (7.5 MW) and one new steam unit (49.8 MW) were offered into the auction.

The downward sloping demand curve resulted in more capacity cleared in the market than the reliability requirement. The 132,231.8 unforced MW of cleared resources for the entire RTO represented a reserve margin of 17.8 percent, which was 1,784.0 MW greater than the reliability requirement of 130,447.8 MW (IRM of 15.0 percent).[54,55,56] As shown in Figure 5-2, the downward sloping demand curve resulted in a price of $102.04 per MW-day. Net excess was 8,265.5 MW, which was an increase of 3,254.4 MW from the net excess of 5,011.1 MW in the 2008/2009 RPM Auction. (See Table 5-5.) This increase was mainly because of an increase in ILR from 3,608.1 MW to 6,481.5 MW. Certified ILR was 6,481.5 MW.

As shown in Table 5-12, the net load price that LSEs will pay is $104.82 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.

50 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region" (June 1, 2007) (Accessed January 20, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/raa.ashx> (882.99 KB).

51 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.

52 If all of the exports had been offered into the auction at $0.00 per MW-day, the clearing price would have been approximately $82.00 per MW-day.

53 FRR entities are allowed to offer into the RPM Auction excess volumes above their FRR quantities, subject to a sales' cap amount. The 450.2 MW are excess volumes included in the sales' cap amount which were not offered into the auction.

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

55 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 adjusted for any FRR DR.

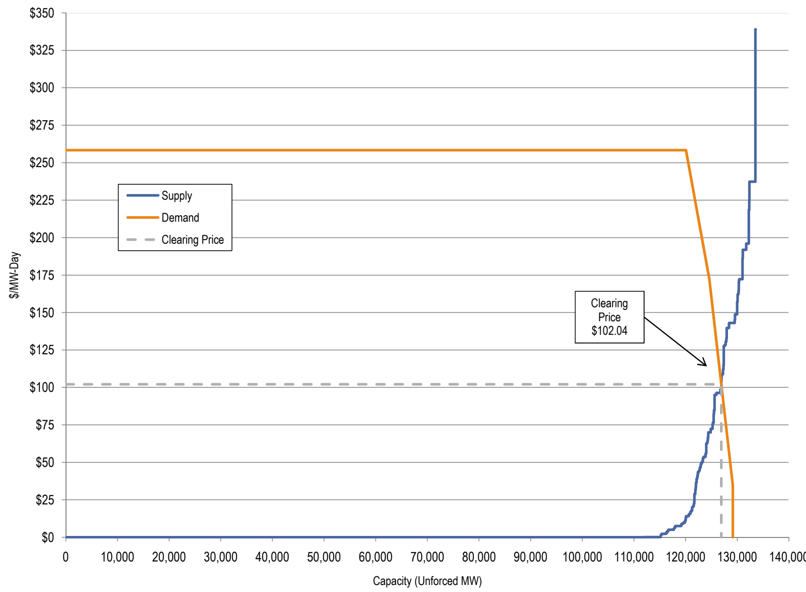
56 The demand curve UCAP quantities are based on three points, which are ratios of the installed reserve margin (IRM=15.0 percent) times the reliability requirement, less the forecast RTO ILR obligation. For the three points, the ratios are 1.12/1.15, 1.16/1.15 and 1.20/1.15. For these three points the 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 2009/2010, CONE was $197.83 per MW-day and E&AS was $36.12 MW-day.

Table 5-12 RTO offer statistics: 2009/2010 RPM Base Residual Auction[57]

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total Internal RTO Capacity (Gen and DR)	166,639.7	157,318.2		
FRR	(25,316.2)	(23,523.2)		
Imports	2,652.5	2,505.4		
RPM Capacity	143,976.0	136,300.4		
Exports	(2,376.2)	(2,194.9)		
FRR Optional	(552.5)	(450.2)		
Excused	(136.8)	(104.3)		
Available	140,910.5	133,551.0	100.0%	100.0%
Generation Offered	140,003.6	132,614.2	99.4%	99.3%
DR Offered	906.9	936.8	0.6%	0.7%
Total Offered	140,910.5	133,551.0	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	133,859.0	126,917.1	95.0%	95.0%
Cleared in LDAs	5,594.4	5,314.7	4.0%	4.0%
Total Cleared	139,453.4	132,231.8	99.0%	99.0%
Uncleared in RTO	895.5	869.0	0.6%	0.7%
Uncleared in LDAs	561.6	450.2	0.4%	0.3%
Total Uncleared	1,457.1	1,319.2	1.0%	1.0%
Reliability Requirement		130,447.8		
Total Cleared		132,231.8		
ILR Certified		6,481.5		
RPM Net Excess/(Deficit)		8,265.5		
Resource Clearing Price ($ per MW-day)		$102.04	A	
Final Zonal Capacity Price ($ per MW-day)		$104.82	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$0.00	C	
Final Zonal ILR Price ($ per MW-day)		$102.04	A-C	
Net Load Price ($ per MW-day)		$104.82	B-C	

57 Prices are only for those generating units outside of MAAC+APS and SWMAAC.

Figure 5-2 RTO market supply/demand curves: 2009/2010 RPM Base Residual Auction[58]



MAAC+APS

Table 5-13 shows total MAAC+APS offer data for the 2009/2010 RPM Auction. Total internal MAAC+APS unforced capacity of 73,012.9 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 89.3 MW into MAAC+APS, RPM unforced capacity was 73,102.2 MW.[59] This amount was reduced by 104.3 MW which were excused from the RPM must-offer requirement as a result of non-utility (NUG) ownership questions (57.2 MW), planned reductions due to environmental regulations (33.5 MW), planned capacity withdrawals (5.5 MW) generation moving behind the meter (4.0 MW) and other factors (4.1 MW), resulting in 72,997.9 MW that were available to be offered into the auction. All capacity resources were offered into the RPM Auction.

Of the 72,547.7 MW cleared in MAAC+APS, 67,233.0 MW were cleared in the RTO before MAAC+APS became constrained. Once the constraint was binding, based on the 4,941.0 MW CETL value, only the incremental supply located in MAAC+APS was available to meet the incremental demand in the LDA. Of the 5,764.9 MW of incremental supply, 5,314.7 MW cleared, which resulted in a resource-clearing price of $191.32 per MW-day, as shown in Figure 5-3. 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.

Total resources in MAAC+APS were 77,488.7 MW, which when combined with certified ILR of 3,081.0 MW resulted in a net excess of 2,666.8 MW (3.4 percent) greater than the reliability requirement of 77,902.9 MW.

58 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 MAAC+APS and SWMAAC.

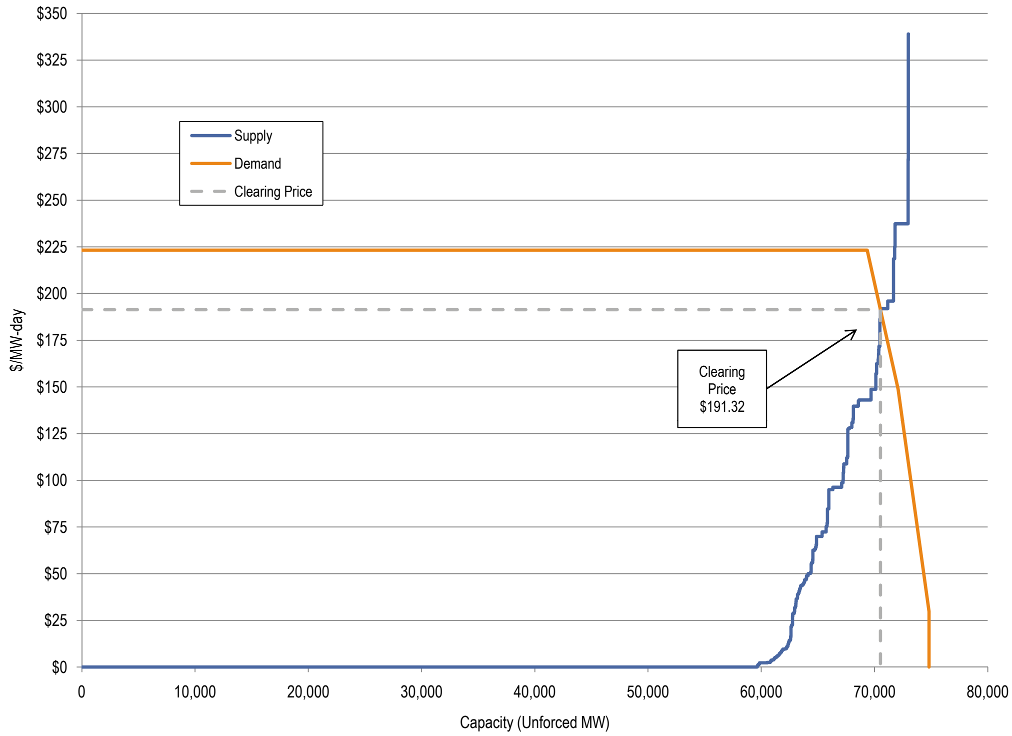
59 Rules for RPM auctions state that imports are modeled in the unconstrained region of the RTO. See PJM. "Manual 18: PJM Capacity Market," Revision 8 (Effective January 1, 2010), p. 24, <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.27 MB). The import MW into MAAC+APS consist of MW under a grandfathered agreement related to Rural Electric Cooperatives (RECs) generation.

As shown in Table 5-13, the net load price that LSEs will pay is $193.77 per MW-day. This value is the final zonal capacity price ($196.54 per MW-day) less the final CTR credit rate ($2.77 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 5-13 MAAC+APS offer statistics: 2009/2010 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total Internal MAAC+APS Capacity (Gen and DR)	77,870.6	73,012.9		
Imports	89.3	89.3		
RPM Capacity	77,959.9	73,102.2		
Exports	0.0	0.0		
Excused	(136.8)	(104.3)		
Available	77,823.1	72,997.9	100.0%	100.0%
Generation Offered	77,028.6	72,177.3	99.0%	98.9%
DR Offered	794.5	820.6	1.0%	1.1%
Total Offered	77,823.1	72,997.9	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	71,667.1	67,233.0	92.1%	92.1%
Cleared in LDAs	5,594.4	5,314.7	7.2%	7.3%
Total Cleared	77,261.5	72,547.7	99.3%	99.4%
Uncleared	561.6	450.2	0.7%	0.6%
Reliability Requirement		77,902.9		
Total Cleared		72,547.7		
CETL		4,941.0		
Total Resources		77,488.7		
ILR Certified		3,081.0		
RPM Net Excess/(Deficit)		2,666.8		
Resource Clearing Price ($ per MW-day)		$191.32	A	
Final Zonal Capacity Price ($ per MW-day)		$196.54	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$2.77	C	
Final Zonal ILR Price ($ per MW-day)		$188.55	A-C	
Net Load Price ($ per MW-day)		$193.77	B-C	

Figure 5-3 MAAC+APS supply/demand curves: 2009/2010 RPM Base Residual Auction[60]



SWMAAC

Table 5-14 shows total SWMAAC offer data for the 2009/2010 RPM Auction. Total internal SWMAAC unforced capacity of 10,345.2 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 10,345.2 MW. This amount was reduced by 33.5 MW which were excused from the RPM must-offer requirement as a result of planned reductions due to environmental regulations, resulting in 10,311.7 MW that were available to be offered into the auction. All capacity resources were offered into the RPM Auction.

Of the 9,914.6 MW cleared in SWMAAC, 6,202.3 MW had cleared in the RTO before SWMAAC became constrained. Once the constraint was binding, based on the 6,391.0 CETL value, only the incremental supply in SWMAAC was available to meet incremental demand in the LDA. Of the 2,413.7 MW of incremental supply, 2,016.6 MW cleared, which resulted in a resource clearing price of $237.33 per MW-day. (See Figure 5-4)

Total resources in SWMAAC were 16,305.6 MW, which when combined with certified ILR of 519.3 MW resulted in a net excess of 506.1 MW (3.1 percent) greater than the reliability requirement of 16,318.8 MW.

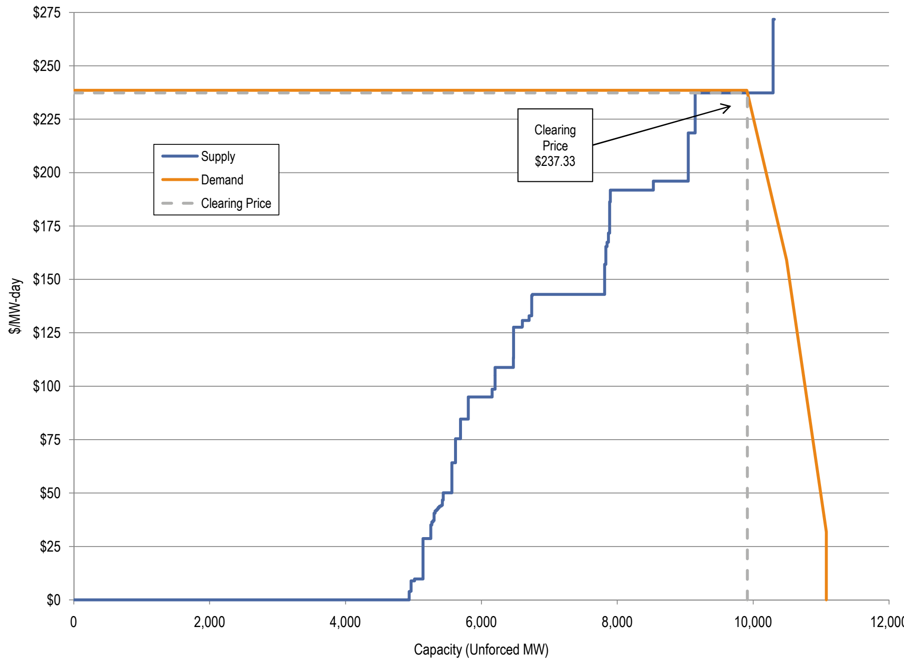
60 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve excludes incremental demand which cleared in SWMAAC.

As shown in Table 5-14, the net load price that LSEs will pay is $224.59 per MW-day. This value is the final zonal capacity price ($243.80 per MW-day) less the final CTR credit rate ($19.21 per MW-day).

Table 5-14 SWMAAC offer statistics: 2009/2010 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total Internal SWMAAC Capacity (Gen and DR)	11,448.6	10,345.2		
Imports	0.0	0.0		
RPM Capacity	11,448.6	10,345.2		
Exports	0.0	0.0		
Excused	(37.0)	(33.5)		
Available	11,411.6	10,311.7	100.0%	100.0%
Generation Offered	11,066.7	9,955.4	97.0%	96.5%
DR Offered	344.9	356.3	3.0%	3.5%
Total Offered	11,411.6	10,311.7	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	7,001.2	6,202.3	61.4%	60.1%
Cleared in MAAC+APS	1,784.3	1,695.7	15.6%	16.4%
Cleared in LDA	2,146.2	2,016.6	18.8%	19.6%
Total Cleared	10,931.7	9,914.6	95.8%	96.1%
Uncleared	479.9	397.1	4.2%	3.9%
Reliability Requirement		16,318.8		
Total Cleared		9,914.6		
CETL		6,391.0		
Total Resources		16,305.6		
ILR Certified		519.3		
RPM Net Excess/(Deficit)		506.1		
Resource Clearing Price ($ per MW-day)		$237.33	A	
Final Zonal Capacity Price ($ per MW-day)		$243.80	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$19.21	C	
Final Zonal ILR Price ($ per MW-day)		$218.12	A-C	
Final Net Load Price ($ per MW-day)		$224.59	B-C	

Figure 5-4 SWMAAC supply/demand curves: 2009/2010 RPM Base Residual Auction



2009/2010 RPM Third Incremental Auction

Under RPM, the Third Incremental Auction, which is held in January prior to the start of the delivery year, allows capacity resource owners to buy and sell capacity to accommodate adjustments to participants' resource positions as a result of resource retirements, cancellations, delays or changes in a resource's EFORd. Prior to the 2012/2013 delivery year, the demand curve in the Third Incremental Auction is entirely a function of demand bids, and there is no administrative market demand curve.

Cleared resources across the entire RTO will receive a total of $47.7 million based on the unforced MW cleared and the prices in the 2009/2010 RPM Third Incremental Auction.

RTO

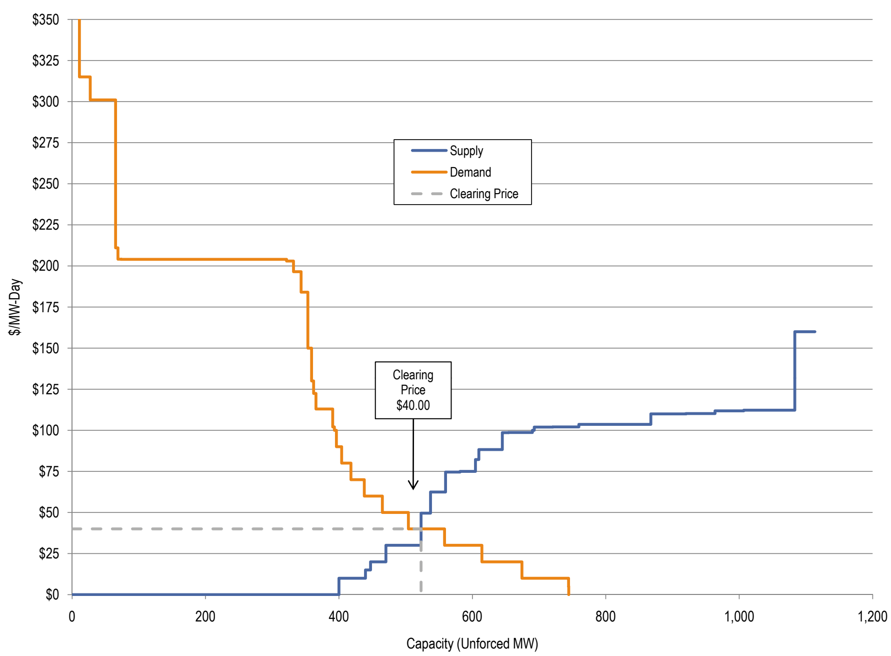
Table 5-15 shows total RTO offer and bid data for the 2009/2010 RPM Third Incremental Auction. There were 3,255.8 MW offered into the incremental auction while buy bids totaled 2,697.6 MW. The offered volumes came from uncleared offers from the 2009/2010 BRA, capacity and DR modifications to existing capacity resources, additional capacity from resources that were not previously capacity resources, and additional UCAP due to improved EFORds. Buy bids were submitted to cover short positions due to deratings and EFORd increases or because participants wished to purchase additional capacity. No EFORd offer segments were permitted in this auction because the delivery year EFORds were known for this auction and the EFORd risk was therefore zero. Cleared volumes in the RTO were 1,798.4 MW, resulting in an RTO clearing price of $40.00

per MW-day (See Figure 5-5.) The price was set by a demand bid. The RTO clearing price in the 2009/2010 BRA was $102.04 per MW-day. The 1,457.4 MW of uncleared volumes can be used as replacement volumes or traded bilaterally.

Table 5-15 RTO offer statistics: 2009/2010 RPM Third Incremental Auction

	Offered (Supply)		Bid (Demand)
	ICAP (MW)	UCAP (MW)	UCAP (MW)
Generation	2,918.7	2,724.4	
DR	514.6	531.4	
Total	3,433.3	3,255.8	2,697.6
Cleared in RTO	539.9	523.1	523.1
Cleared in MAAC+APS	1,364.1	1,275.3	1,275.3
Total cleared	1,904.0	1,798.4	1,798.4
Uncleared in RTO	589.6	590.4	221.3
Uncleared in MAAC+APS	939.7	867.0	677.9
Total uncleared	1,529.3	1,457.4	899.2
Resource clearing price ($ per MW-day)	$40.00		

Figure 5-5 RTO supply/demand curves: 2009/2010 RPM Third Incremental Auction[61,62]



61 The supply curve includes all supply offers at the lower of offer price or offer cap.
62 For ease of viewing, the graph was truncated at $350 per MW-day and does not show a buy bid of approximately $1,000 per MW-day.

MAAC+APS

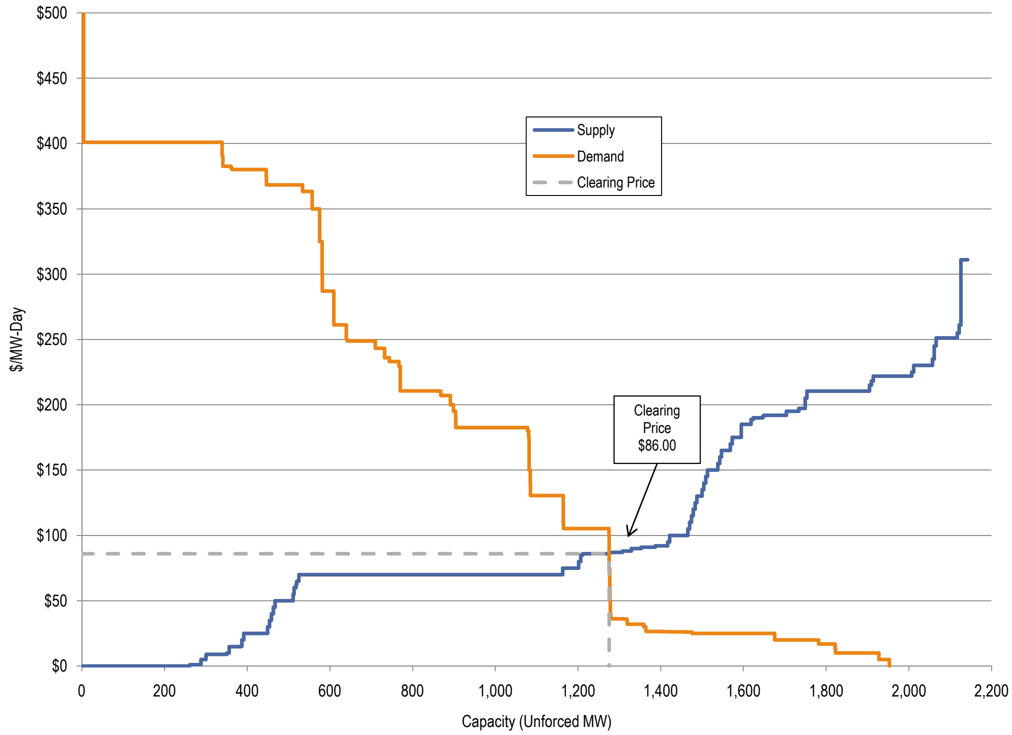
Table 5-16 shows total MAAC+APS offer and bid data for the 2009/2010 RPM Third Incremental Auction. There were 2,142.3 MW in MAAC+APS offered into the auction while buy bids in MAAC+APS totaled 1,953.2 MW. The offered volumes came from uncleared offers from the 2009/2010 BRA, capacity and DR modifications to existing capacity resources, additional capacity from resources that were not previously capacity resources, and additional UCAP due to improved EFORds. Cleared volumes in MAAC+APS were 1,275.3 MW, resulting in a MAAC+APS clearing price of $86.00 per MW-day. (See Figure 5-6) The MAAC+APS clearing price in the 2009/2010 BRA was $191.32 per MW-day.

Although SWMAAC was constrained in the 2009/2010 BRA, supply offers in the incremental auction in SWMAAC (985.1 MW) exceeded SWMAAC demand bids (135.5 MW). The supply and demand curves resulted in a price less than the MAAC+APS clearing price. The result was that all of SWMAAC supply which cleared received the MAAC+APS clearing price.

Table 5-16 MAAC+APS offer statistics: 2009/2010 RPM Third Incremental Auction

	Offered (Supply)		Bid (Demand)
	ICAP (MW)	UCAP (MW)	UCAP (MW)
Generation	2,043.3	1,873.3	
DR	260.5	269.0	
Total	2,303.8	2,142.3	1,953.2
Cleared in RTO	487.3	462.9	
Cleared in MAAC+APS	876.8	812.4	
Total cleared	1,364.1	1,275.3	1,275.3
Uncleared	939.7	867.0	677.9
Resource clearing price ($ per MW-day)	$86.00		

Figure 5-6 MAAC+APS supply/demand curves: 2009/2010 RPM Third Incremental Auction[63]



Generator Performance

Generator performance results from the interaction between the physical nature of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. 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).[64]

Generator Performance Factors

Generator performance factors are based on a defined period, usually a year, and are directly comparable.[65] 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

63 The supply curve includes all supply offers at the lower of offer price or offer cap.

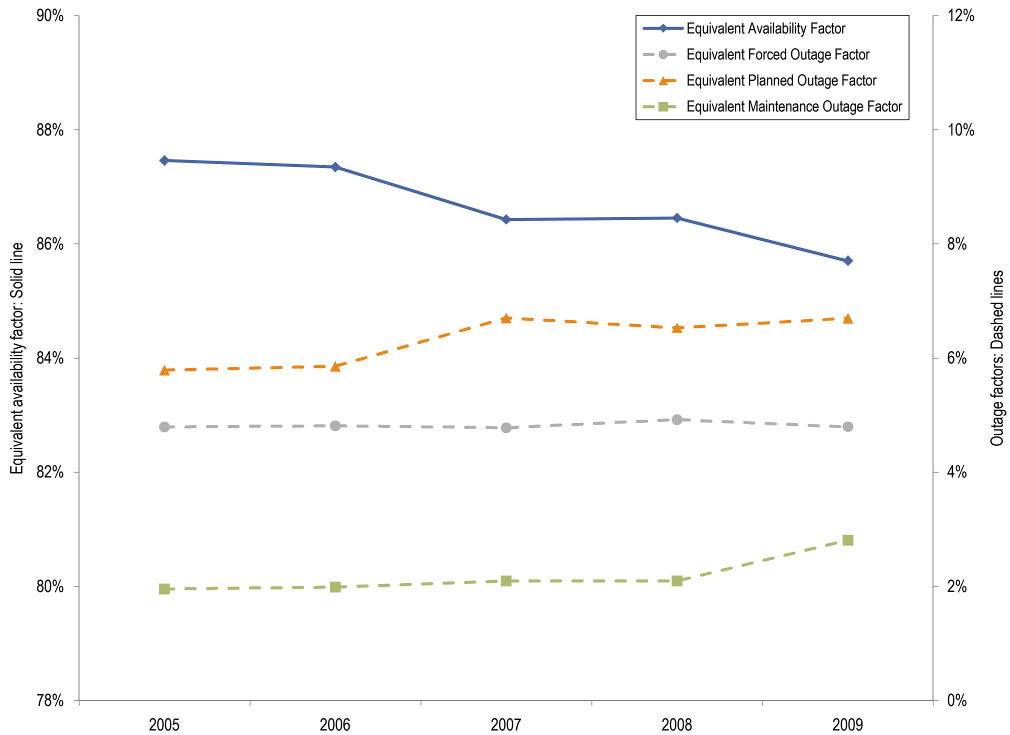
64 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM GADS database. This set of capacity resources may include generators in addition to those in the set of generators committed as resources in the RPM.

65 Data from all PJM capacity resources for the years 2005 through 2009 were analyzed.

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 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 86.5 percent in 2008 to 85.7 percent in 2009. The EFOF decreased 0.126 percentage points from 2008 to 4.796 percent in 2009, while the EPOF increased by 0.165 percentage points to 6.694 and the EMOF increased 0.714 percentage points to 2.808.[66] (See Figure 5-7)

Figure 5-7 PJM equivalent outage and availability factors: Calendar years 2005 to 2009



Generator Forced Outage Rates

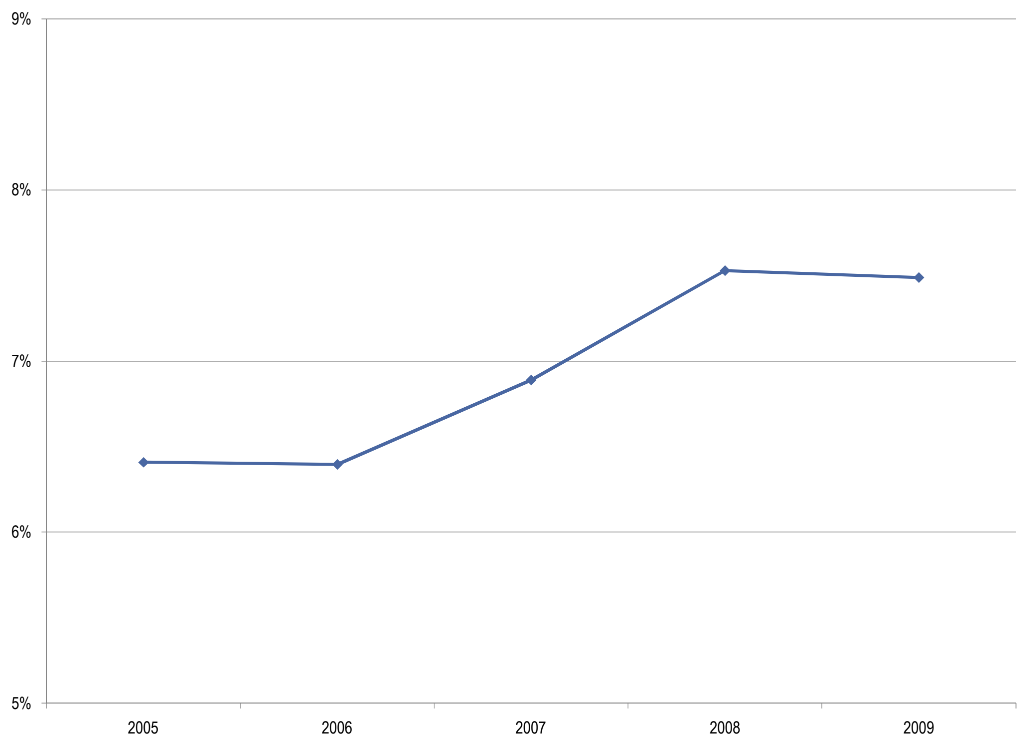
The equivalent demand forced outage rate (EFORd) (generally referred to as the forced outage rate) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd is calculated using historical performance data. PJM systemwide EFORd is a capacity-weighted average of individual unit EFORd. Unforced capacity in the PJM Capacity Market for any individual generating unit is equal to one minus the EFORd adjusted to exclude Outside Management Control (OMC) events multiplied by the unit's

66 The performance factor data include all units from PJM. Results for prior years may be different from previous reports as corrections can be made at any time with permission from the PJM GADS administrators. Data are for the year ending December 31, 2009, as downloaded from the PJM GADS database on February 23, 2010.

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 (unforced capacity) is inversely related to the forced outage rate.

EFORd calculations use historical data, including equivalent forced outage hours,[67] service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[68] The average PJM EFORd changed from 6.4 percent in 2005 and 2006 to 6.9 percent in 2007 and to 7.5 percent in 2008 and 2009.[3] Average PJM EFORd was significantly affected by a single nuclear unit, AEP's Cook Nuclear Plant Unit 1, which was on forced outage for a majority of the year.[69] If this unit were excluded from the results, 2009 EFORd would decrease to 6.9 percent. Figure 5-8 shows the average EFORd since 2005 for all units in PJM.

Figure 5-8 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2005 to 2009



Distribution of EFORd

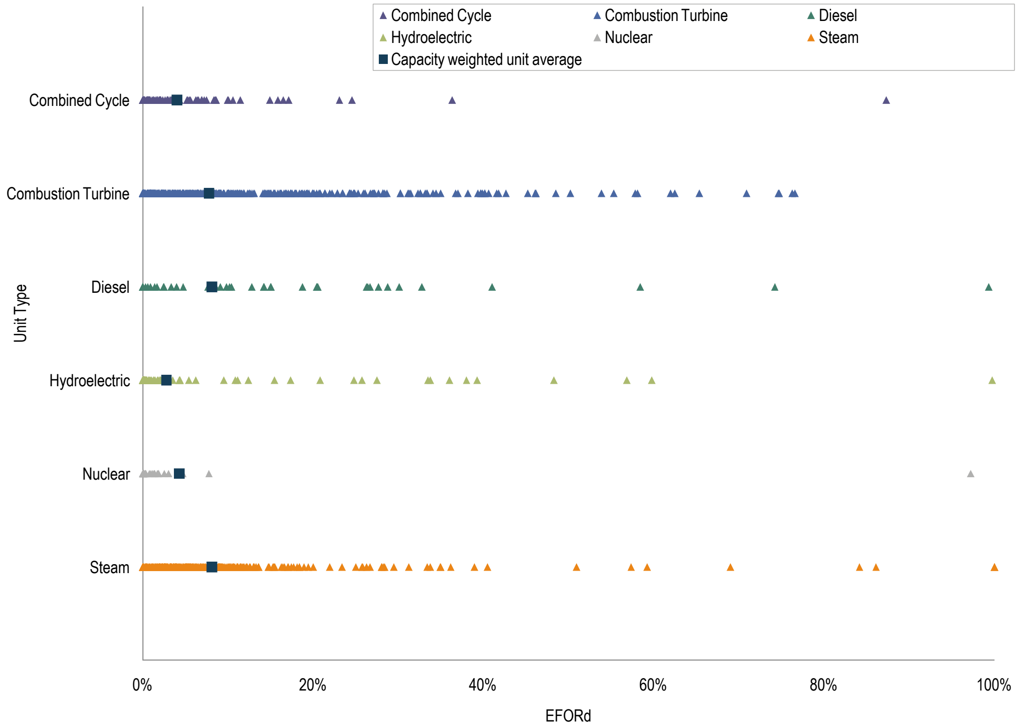
The average EFORd results do not show the actual underlying pattern of EFORd rates by unit type. The distribution of EFORd by unit type is shown in Figure 5-9. Each generating unit is represented by a single point, and the capacity weighted unit average is represented by a solid square.

67 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.

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

69 "AEP´s Cook Nuclear Unit 1 Reaches Full Reactor Power." AEP press release, December 23, 2009. <http://www.aep.com/newsroom/newsreleases/?id=1582>.

Figure 5-9 PJM 2009 Distribution of EFORd data by unit type



Components of EFORd

Table 5-17 compares PJM EFORd data by unit type to the five-year North American Electric Reliability Council (NERC) average EFORd data for corresponding unit types. The 2009 PJM forced outage rates for combined cycle, diesel and hydroelectric units were below the NERC five-year averages. The 2009 PJM EFORd for combustion turbine, nuclear and fossil steam units exceeded the NERC averages.[70]

Table 5-17 Five-year PJM EFORd data comparison to NERC five-year average for different unit types: Calendar years 2005 to 2009

	2005	2006	2007	2008	2009	NERC EFORd 2004 to 2008 Average
Combined Cycle	5.0%	4.3%	3.4%	3.4%	3.8%	6.1%
Combustion Turbine	8.9%	9.4%	11.0%	11.0%	9.8%	8.5%/8.3%
Diesel	14.0%	13.2%	12.0%	11.4%	10.2%	10.5%
Hydroelectric	2.5%	1.9%	2.1%	2.0%	3.2%	4.7%
Nuclear	1.6%	1.4%	1.4%	1.9%	4.1%	3.2%
Steam	8.1%	8.2%	9.1%	10.1%	9.3%	6.9%
Total	6.4%	6.4%	6.9%	7.5%	7.5%	NA

70 NERC defines combustion turbines in two categories: jet engines and gas turbines. The EFORd for the 2004 to 2008 period are 8.5 percent for jet engines and 8.3 percent for gas turbines per NERC's GADS "2004-2008 Generating Availability Report"<http://www.nerc.com/files/gar2008.zip>(2.46 MB). Also, the NERC average for fossil steam units is a unit-year-weighted value for all units reporting. The PJM values are weighted by capability for each calendar year.

Table 5-18 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.[71] Forced MW for a unit type is the EFORd multiplied by the generator's net dependable summer capability.

Table 5-18 Contribution to EFORd for specific unit types (Percentage points): Calendar years 2005 to 2009[72]

	2005	2006	2007	2008	2009	Change in 2009 from 2008
Combined Cycle	0.6	0.5	0.4	0.5	0.5	0.0
Combustion Turbine	1.3	1.4	1.6	1.7	1.5	(0.1)
Diesel	0.0	0.0	0.0	0.0	0.0	(0.0)
Hydroelectric	0.1	0.1	0.1	0.1	0.1	0.1
Nuclear	0.3	0.3	0.2	0.4	0.8	0.4
Steam	4.1	4.1	4.2	5.0	4.6	(0.4)
Total	6.4	6.4	6.9	7.5	7.5	(0.0)

Steam units continue to be the largest contributor to overall PJM EFORd. The decrease in contribution to EFORd across most unit types with the exception of nuclear is due to a significant increase in the contribution of nuclear EFORd to overall EFORd.

Duty Cycle and EFORd

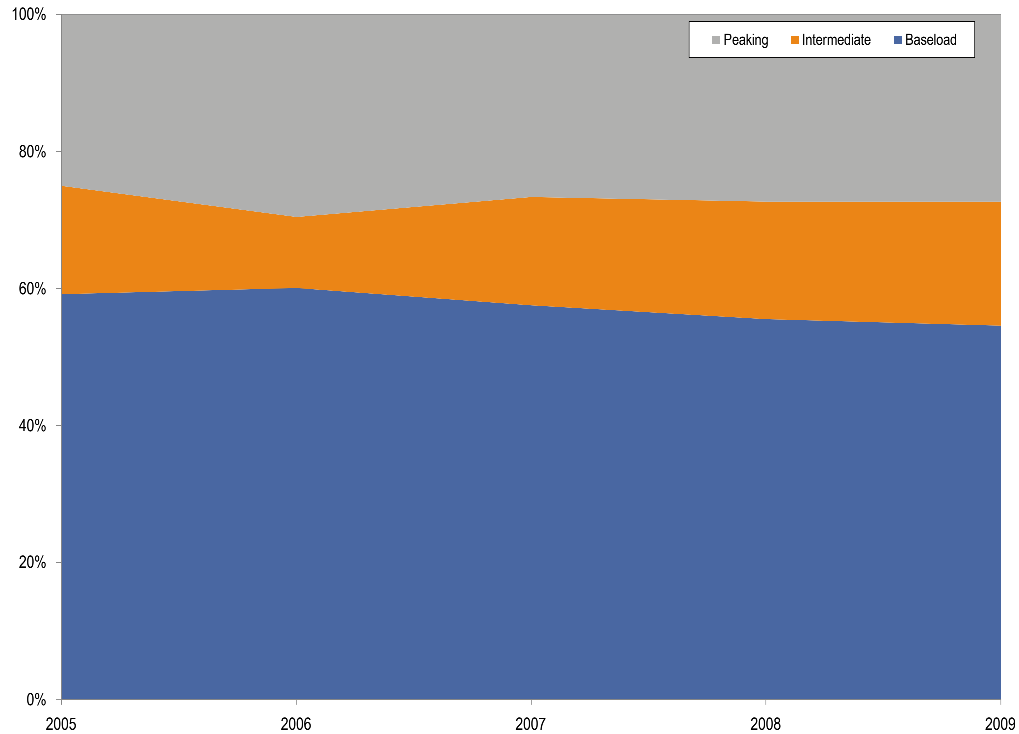
In addition to disaggregating system EFORd by unit type, units were categorized by actual duty cycles as baseload, intermediate or peaking to determine the relationship between type of operation and forced outage rates.[73] Figure 5-10 shows the contribution of unit types to system average EFORd. Total capacity in 2009 consists of 65.0 percent baseload capacity, 13.8 percent intermediate capacity, and 21.2 percent peak capacity.

71 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.

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

73 Duty cycle is the time the unit is generating divided by the time the unit is available to generate. A baseload unit is defined here as a unit that generates during 50 percent or more of its available hours. An intermediate unit is defined here as a unit that generates during from 10 percent to 50 percent of its available hours. A peaking unit is defined here as a unit that generates during less than 10 percent of its available hours.

Figure 5-10 Contribution to EFORd by duty cycle: Calendar years 2005 to 2009



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.[74] 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 2009 was 85.7 percent; the corresponding EMOF and EPOF were 2.8 percent and 6.7 percent, respectively. As a result, the 2009 PJM EFOF was 4.8 percent. This means 4.8 percent lost availability because of forced outages.

The major reasons for this lost equivalent availability are listed in Table 5-19.

74 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 5-19 Outage cause contribution to PJM EFOF: Calendar year 2009

	Percentage Point Contribution to EFOF	Contribution to EFOF
Boiler Tube Leaks	0.84	17.6%
Low Pressure Turbine	0.75	15.6%
Economic	0.47	9.7%
Electrical	0.32	6.7%
Boiler Air and Gas Systems	0.20	4.2%
Generator	0.18	3.9%
Boiler Fuel Supply from Bunkers to Boiler	0.13	2.6%
Fuel Quality	0.12	2.6%
Stack Emission	0.10	2.1%
Boiler Piping System	0.10	2.0%
Controls	0.09	1.8%
High Pressure Turbine	0.08	1.7%
Feedwater System	0.08	1.7%
Performance	0.08	1.7%
Condensing System	0.07	1.4%
Inlet Air System and Compressors	0.07	1.4%
Boiler Tube Fireside Slagging or Fouling	0.07	1.4%
Valve	0.07	1.4%
Miscellaneous (Generator)	0.06	1.2%
All Other Causes	0.92	19.2%
Total	4.80	100.0%

Table 5-19 shows that boiler tube leaks, at 17.6 percent of the systemwide EFOF, were the largest single contributor to EFOF. Forced outages because of boiler tube leaks reduced system equivalent availability by 0.84 percentage points. Forced outages because of low pressure turbine problems caused the second largest reduction to equivalent availability by 0.75 percentage points. Economic reasons caused the third largest reduction to equivalent availability by 0.47 percentage points, or 9.7 percent of the systemwide EFOF.

Table 5-20 shows the categories which are included in the economic category.[75] Lack of fuel that is considered Outside Management Control accounted for 87.6 percent of all economic reasons while lack of fuel that was not Outside Management Control accounted for only 6.5 percent.

75 The classification and definitions of these outages are defined by NERC GADS.

Table 5-20 Contributions to Economic Outages: 2009

	Contribution to Economic Reasons
Lack of Fuel (OMC)	87.6%
Lack of Fuel (Non-OMC)	6.5%
Other Economic Problems	5.4%
Lack of Water (Hydro)	0.4%
Fuel Conservation	0.1%
Problems with Primary Fuel for Units with Secondary Fuel Operation	0.0%
Total	100.0%

Table 5-21 Contribution to EFOF by unit type for the most prevalent causes: Calendar year 2009

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	1.2%	0.0%	0.0%	0.0%	0.0%	24.8%	17.6%
Low Pressure Turbine	0.1%	0.0%	0.0%	0.0%	78.7%	5.5%	15.6%
Economic	3.5%	13.9%	1.5%	1.3%	0.0%	12.3%	9.7%
Electrical	11.6%	16.5%	0.5%	25.5%	6.1%	5.1%	6.7%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	5.9%	4.2%
Generator	9.8%	1.7%	0.7%	42.2%	0.0%	3.2%	3.9%
Boiler Fuel Supply from Bunkers to Boiler	0.2%	0.0%	0.0%	0.0%	0.0%	3.7%	2.6%
Fuel Quality	0.0%	0.0%	13.4%	0.0%	0.0%	3.6%	2.6%
Stack Emission	0.0%	0.3%	0.2%	0.0%	0.0%	3.0%	2.1%
Boiler Piping System	0.9%	0.0%	0.0%	0.0%	0.0%	2.7%	2.0%
Controls	1.2%	1.1%	0.5%	0.5%	0.7%	2.2%	1.8%
High Pressure Turbine	0.0%	0.0%	0.0%	0.0%	0.0%	2.4%	1.7%
Feedwater System	4.1%	0.0%	0.0%	0.0%	0.0%	2.0%	1.7%
Performance	1.9%	10.2%	5.8%	2.2%	0.6%	1.3%	1.7%
Condensing System	0.1%	0.0%	0.0%	0.0%	0.4%	2.0%	1.4%
Inlet Air System and Compressors	9.0%	14.8%	0.0%	0.0%	0.0%	0.0%	1.4%
Boiler Tube Fireside Slagging or Fouling	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%	1.4%
Valve	1.3%	0.0%	0.0%	0.0%	1.1%	1.6%	1.4%
Miscellaneous (Generator)	7.8%	1.7%	0.1%	0.6%	0.0%	0.8%	1.2%
All Other Causes	47.1%	39.8%	77.2%	27.6%	12.5%	15.8%	19.2%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-21 shows the major causes of EFOF by unit type. Boiler tube leaks caused 24.8 percent of the EFOF for fossil steam units. Low pressure turbine problems caused 78.7 percent of the EFOF for nuclear units. Generator outages caused 42.2 percent of the EFOF for hydroelectric units. Some generator outages include outages caused by problems with the stator windings, bushings, and terminals and the bearing cooling system.[12]

Table 5-22 Contribution to EFOF by unit type: Calendar year 2009

	EFOF	Contribution to EFOF
Combined Cycle	2.6%	6.8%
Combustion Turbine	1.8%	5.6%
Diesel	7.5%	0.3%
Hydroelectric	2.3%	1.9%
Nuclear	4.1%	14.9%
Steam	6.8%	70.5%
Total	4.8%	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 49.1 percent) of the capacity mix, have a high duty cycle and in 2009 had an EFORd of 9.3 percent which yields a 69.8 percent contribution to PJM systemwide EFOF. Nuclear units also have a high duty cycle; their share of the PJM systemwide capacity mix is about 18.3 percent and in 2009 they had a 4.1 percent EFORd which yields a 14.9 percent contribution to PJM systemwide EFOF. By using the values in Table 5-22 and Table 5-21 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 5-21 multiplied by the contribution value in Table 5-22 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 to be deemed Outside Management Control (OMC) in response to the system disturbance of August 14, 2003.[76] NERC specified, in its January 2006 update to the "Generator Availability Data System Data Reporting Instructions,"[77] in Appendix K,[78] 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.[79] 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

76 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."

77 The "Generator Availability Data System Data Reporting Instructions" can be found on the NERC website: <http://www.nerc.com/files/2009_GADS_DRI_Complete_Set.pdf> (4.9 MB).

78 The "Generator Availability Data System Data Reporting Instructions," Appendix K can be found on the NERC website: <http://www.nerc.com/files/Appendix_K_Outside_Plant_Management_Control.pdf> (161 KB).

79 For a list of these cause codes, see the *2009 State of the Market Report for PJM*, Volume II, Appendix E, "Capacity Market."

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 2008 and 2009, no 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, 6 percent of the lost generation because of "low Btu coal" was deemed OMC, in 2008, 12 percent of the lost generation because of "low Btu coal" was deemed OMC, and in 2009, 2.3 percent of the lost generation because of "low Btu coal" was deemed OMC. It is not clear why some companies exclusively used the OMC cause codes and did not use the non-OMC cause code for "low Btu coal" in 2006. 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. Neither reason is necessarily the basis for designating a related outage as an OMC event.

All outages, including OMC outages, are included in the EFORd that is used for planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations used to determine the level of unforced capacity for specific units and thus the amount of unforced capacity that must be offered in PJM Capacity Markets. This modified EFORd is termed the XEFORd. All submitted OMC outages are reviewed by PJM's Resource Adequacy Department. Table 5-23 shows the impact of OMC outages on EFORd for 2009. The difference is especially noticeable for steam units and combustion turbine units. For steam units, the OMC outage reason that resulted in the highest total MW loss in 2009 was lack of fuel. Combustion turbine units have natural gas fuel curtailment outages that were also classified 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 2009, steam XEFORd was 1.3 percentage points less than EFORd, which translates into a 1,057 MW difference in unforced capacity.

The MMU recommends that PJM review all requests for OMC carefully, develop a transparent set of rules governing the designation of outages as OMC and post those guidelines.

Table 5-23 PJM EFORd vs. XEFORd: Calendar year 2009

	2009 EFORd	2009 XEFORd	Difference
Combined Cycle	3.8%	3.6%	0.2%
Combustion Turbine	9.8%	8.3%	1.5%
Diesel	10.2%	8.0%	2.2%
Hydroelectric	3.2%	3.0%	0.2%
Nuclear	4.1%	4.1%	0.0%
Steam	9.3%	8.0%	1.3%
Total	7.5%	6.6%	0.9%

Components of EFORp

The equivalent forced outage rate during peak hours (EFORp) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate during the peak hours of the day in the peak months of January, February, June, July and August. EFORp is calculated using historical performance data and is designed to measure if a unit would have run had the unit not been forced out. EFORp excludes OMC outages. PJM systemwide EFORp is a capacity-weighted average of individual unit EFORp.

Table 5-24 shows the contribution of each unit type to the system EFORp, calculated as the total forced MW for the unit type divided by the total capacity of the system. Forced MW for a unit type is the EFORp multiplied by the generator's net dependable summer capability.

Table 5-24 Contribution to EFORp by unit type (Percentage points): Calendar years 2008 to 2009

	2008	2009
Combined Cycle	0.3	0.4
Combustion Turbine	0.5	0.4
Diesel	0.0	0.0
Hydroelectric	0.1	0.1
Nuclear	0.2	0.8
Steam	3.5	2.3
Total	4.5	4.0

In Table 5-25, note that EFORp for nuclear units in 2009 was significantly affected by a single nuclear unit, AEP's Cook Nuclear Plant Unit 1, which was on forced outage for a majority of the year.

Table 5-25 PJM EFORp data by unit type: Calendar years 2008 to 2009

	2008	2009
Combined Cycle	2.5%	2.9%
Combustion Turbine	3.4%	2.5%
Diesel	5.8%	5.3%
Hydroelectric	1.3%	2.9%
Nuclear	0.9%	4.3%
Steam	7.1%	4.7%
Total	4.5%	4.0%

EFORd, XEFORd and EFORp

EFORd, XEFORd and EFORp are designed to measure the rate of forced outages, which are defined as outages that cannot be postponed beyond the end of the next weekend.[80] It is reasonable to expect that units have some degree of control over when to take a forced outage, depending on the underlying cause of the forced outage. If units had no control over the timing of forced outages, outages during peak hours of the peak months would be expected to occur at roughly the same rate as outages during periods of demand throughout the rest of the year. With the exception of nuclear units, EFORp is lower than both EFORd and XEFORd, suggesting that units elect to take forced outages during off-peak hours, as much as it is within their control to do so. That is consistent with

80 See PJM. "Manual 22: Generator Resource Performance Indices," Revision 15 (June 1, 2007), Definitions.

the incentives created by the PJM Capacity Market. EFORp of nuclear units is slightly higher than EFORd and XEFORd, suggesting that nuclear units have a slightly higher rate of forced outages during the peak months of January, February, June, July and August.

Table 5-26 shows the contribution of each unit type to the system EFORd, XEFORd and EFORp, calculated as the total forced MW for the unit type divided by the total capacity of the system. Table 5-27 shows the capacity-weighted class average of EFORd, XEFORd and EFORp.

Table 5-26 Contribution to PJM EFORd, XEFORd and EFORp by unit type: Calendar year 2009

	EFORd	XEFORd	EFORp
Combined Cycle	0.5	0.5	0.4
Combustion Turbine	1.5	1.3	0.4
Diesel	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.1
Nuclear	0.8	0.7	0.8
Steam	4.6	4.0	2.3
Total	7.5	6.6	4.0

Table 5-27 PJM EFORd, XEFORd and EFORp data by unit type: Calendar year 2009

	EFORd	XEFORd	EFORp
Combined Cycle	3.8%	3.6%	2.9%
Combustion Turbine	9.8%	8.3%	2.5%
Diesel	10.2%	8.0%	5.3%
Hydroelectric	3.2%	3.0%	2.9%
Nuclear	4.1%	4.1%	4.3%
Steam	9.3%	8.0%	4.7%
Total	7.5%	6.6%	4.0%

Comparison of Expected and Actual Performance

If the EFORd based planning assumptions were consistent with actual unit performance, the distribution of actual performance would be identical to a hypothetical normal distribution based on average EFORd performance.

This analysis was performed based on resource-specific EFORd and Summer Net Capability capacity values for the year ending December 31, 2009.[81] These values were used to estimate a

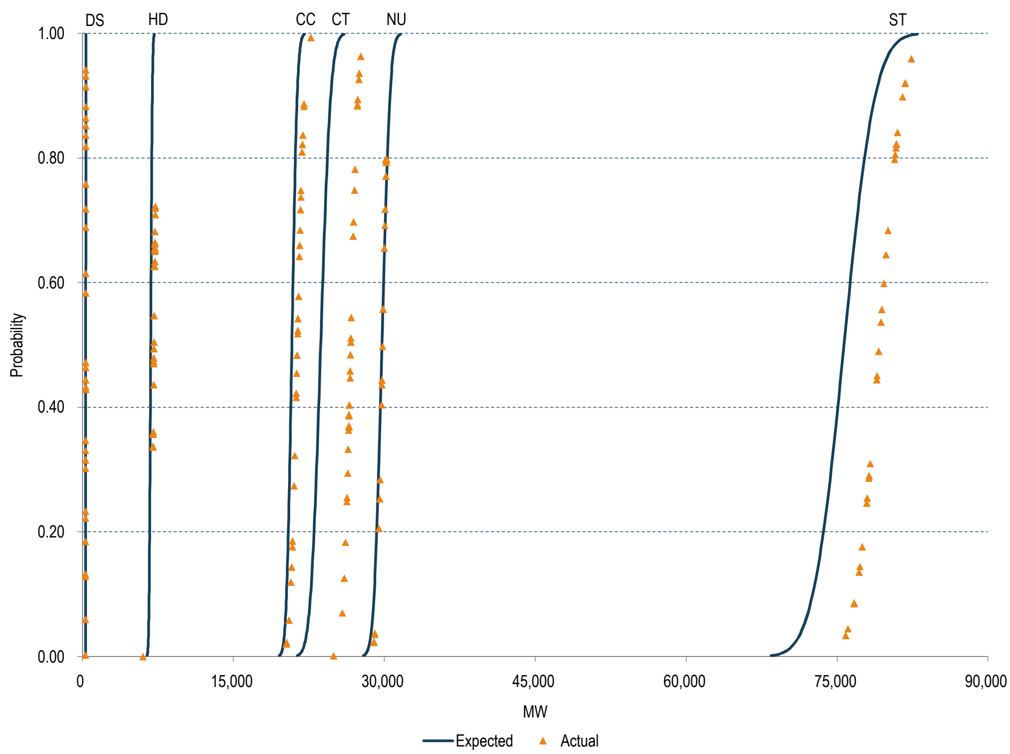
81 See PJM. "Manual 21: Rules and Procedures for Determination of Generating Capability," Revision 08 (January 1, 2010), Summer Net Capability.

normal distribution for each unit type,[82] which was superimposed on a distribution of actual historical availability for the same resources for the year ending December 31, 2009.[83] The top thirty load days were selected for each year and the performance of the resources was evaluated for the peak hour of those days, a sample of 30 peak load hours.

Figure 5-11 compares the normal distribution to the actual distribution based on the defined sample.

Overall, generating units performed better during the selected peak hours than would have been expected based on the EFORd statistic. In particular, CT and ST units tend to have more capacity available during the sampled hours than implied by the EFORd statistic.

Figure 5-11 PJM 2009 distribution of EFORd data by unit type



82 The formulas used to approximate the parameters of the normal distribution are defined as:

$$\text{Mean} = \sum_i \left[\text{MW}_i * \left(1 - \text{EFORd}_i\right) \right]$$

$$\text{Variance} = \sum_i \left[\text{MW}_i * \text{MW}_i * \left(1 - \text{EFORd}_i\right) * \text{EFORd}_i \right]$$

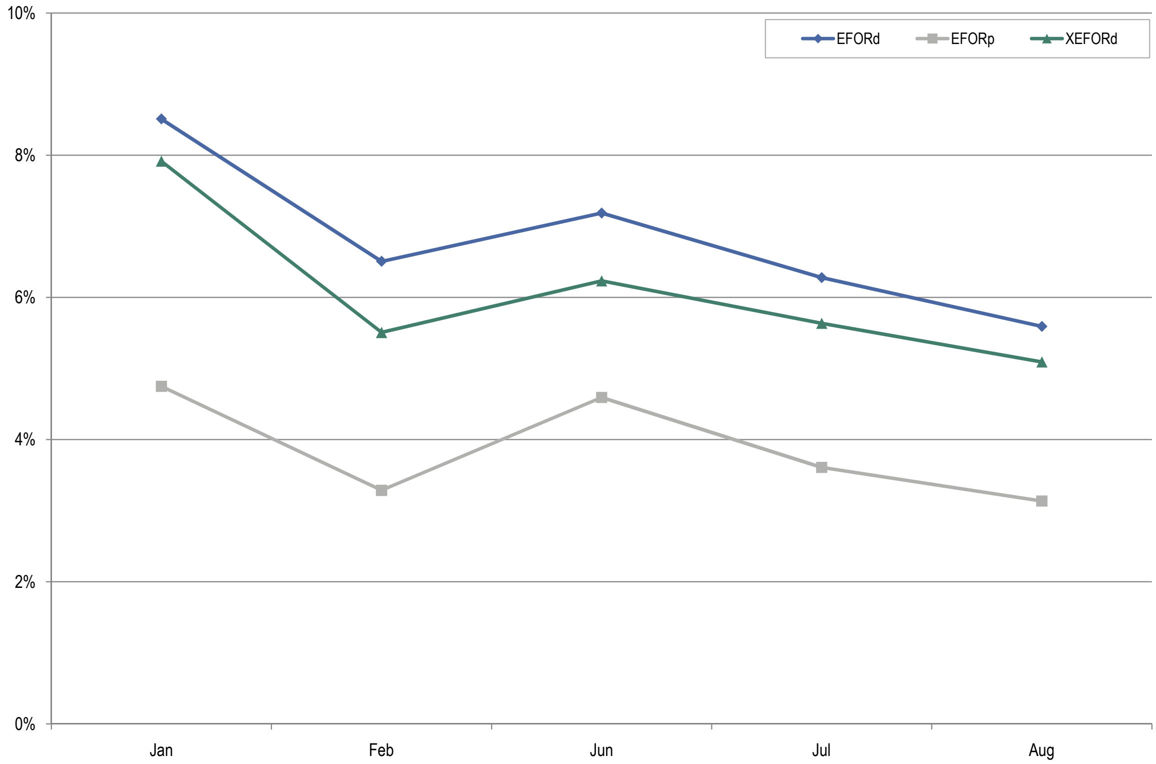
$$\text{Standard Deviation} = \sqrt{\text{Variance}}$$

83 Availability calculated as net dependable capacity affected only by forced outage and forced derating events. Planned and maintenance events were excluded from this analysis.

Performance During Peak Months

For the peak months of January, February, June, July and August, EFORp values were significantly less than EFORd and XEFORd values for the corresponding months as shown in Figure 5-12.

Figure 5-12 PJM peak month data



During the peak months of January, February, June, July and August, unit availability as measured by the equivalent availability factor increased, primarily due to decreasing planned outages, as illustrated in Figure 5-13.

Figure 5-13 PJM peak month generator performance factors