SECTION 5 - CAPACITY MARKETS

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 offering them into the capacity market, or 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 the first nine months of 2009, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.

RPM Capacity Market

Market Design

On June 1, 2007, the RPM Capacity Market design was implemented in the PJM region, replacing the CCM Capacity Market design that had been in place since 1999.[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 RPM Auctions are held for each delivery year, occurring 23, 13 and four months, respectively, prior to the delivery year.[2] Prior to the 2012/2013 delivery year, the second incremental auction is conducted when there is an increase in the region's unforced capacity obligations as a result of a load forecast increase. Also effective for the 2012/2013 delivery year, a conditional incremental auction may be held to address significant unexpected changes that occur after the BRA, such as a delay in planned large transmission upgrades that results in the need for procurement of additional capacity.

RPM prices are locational and may vary depending on transmission constraints.[3] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for the fixed resource requirement (FRR) option. Under RPM, participation by LSEs is mandatory, except for 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. Under RPM there are performance incentives for generation. 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 do not limit prices offered by new entrants. Demand-side resources may be offered directly into RPM auctions and receive the clearing price.

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.[4] This increase was the result of 439.2 MW of new generation, 74.1 MW of generation uprates, and 220.6 MW of demand resource (DR) mods, offset in part by 383.7 MW from 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 offset in part by 890.3 MW from higher EFORds. The reclassification of the Duquesne resources as internal added 3,817.2 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.

1 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2009 Quarterly State of the Market Report for PJM: January through September*, Section 5, "Capacity Market" and include all capacity within the PJM footprint.

2 126 FERC ¶ 61,275 (2009).

3 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.

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

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

In the 2010/2011 auction, 11 more generating resources made offers than in the 2009/2010 RPM auction. The net increase of 11 resources consisted of 15 new resources, four reactivated resources, three resources from the FRR participant, and one resource previously excused, offset by three retired resources, four deactivated resources, three resources exported from PJM, and two resources excused from offering. There were seven new CT resources (270.5 MW), three new diesel resources (16.4 MW), five new wind resources (120.0 MW) and four reactivated resources (165.0 MW) for a total of 19 resources. There were three resources that retired (348.4 MW), four resources that were deactivated (59.6 MW) and an additional three resources exported out of PJM (521.5 MW) for a total of 10 resources.

In the 2011/2012 auction, 21 more generating resources made offers than in the 2010/2011 RPM auction. The net increase of 21 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 FRR resources that did not offer (64.2 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).[5] 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 EDCs and their affiliates maintained a 79.3 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.

- **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 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.

5 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.

- **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 posted 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).[6] 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.

- **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 posted 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 posted 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 posted by the MMU.

- **2012/2013 RPM Base Residual Auction.**[7] 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 posted by the MMU.

6 124 FERC ¶ 61,140 (2008).

7 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>

Generator Performance

- **Forced Outage Rates.** PJM EFORd remained constant at 7.4 percent from 2008 to 2009 (January through August). PJM EFORp decreased from 4.9 percent in 2008 to 3.8 percent in 2009 (January through August).[8] The forced outage rates are for the entire PJM footprint.

- **Generator Performance Factors.** The equivalent availability factor increased from 83.4 percent for the period January through May 2009 to 86.7 percent for the year to date period January through August 2009. This increase was primarily due to a significant decrease in the equivalent planned outage factor and equivalent maintenance outage factor across all unit types during the months June through August 2009.

- **Outages Outside of Management Control (OMC).** PJM permits units to use a forced outage rate (XEFORd) for purposes of selling unforced capacity in the Capacity Market, calculated excluding outages that are designated outside management control. Use of different forced outage metrics for defining reliability targets and for determining available capacity to meet those reliability targets introduces an inconsistency. For example, the EFORd for CTs is 8.8 percent, while the XEFORd for CTs is 7.6 percent. Using artificially reduced outage rates for determining unforced capacity that can be sold in RPM auctions will result in the sale of capacity that is not actually available. A forced outage is a forced outage, from the perspective of system reliability, regardless of the cause.

Conclusion

Market Design

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

8 2008 data are for the 12 months ended December 31, 2008, as downloaded from the PJM GADS database on January 23, 2009. 2009 data are for the 8 months ending August 31, 2009, as downloaded from the PJM GADS database on October 26, 2009. 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.

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.

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, 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.

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.

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 hours defined as critical, 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, but no exercise of market power in the PJM Capacity Market during the first nine months of 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 the first nine months of 2009.

RPM Capacity Market

Table 5-1 Internal capacity: June 1, 2008, through May 31, 2012[9, 10] (See 2008 SOM, Table 5-1)

	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

9 The RTO includes all LDAs. MAAC+APS and MAAC include EMAAC and SWMAAC. EMAAC includes DPL South and PSEG North. Maps of the LDAs can be found in the *2008 State of the Market Report for PJM*, Appendix A, "PJM Geography."

10 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

Table 5-2 PJM Capacity Market load obligation served: June 1, 2009 (See 2008 SOM, Table 5-2)

	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	68,626.9	11,774.2	25,831.0	1,033.8	10,416.7	509.1	15,695.3	133,887.0
Percent of total obligation	51.2%	8.8%	19.3%	0.8%	7.8%	0.4%	11.7%	100.0%

Market Concentration

Preliminary Market Structure Screen

Table 5-3 Preliminary market structure screen results: 2008/2009 through 2012/2013 RPM Auctions (See 2008 SOM, Table 5-3)

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

Table 5-4 RSI results: 2008/2009 through 2012/2013 RPM Auctions (See 2008 SOM, Table 5-4)

RPM Markets	RSI_3	Total Participants	Failed RSI_3 Participants
2008/2009 BRA			
RTO	0.61	65	65
EMAAC	0.25	10	10
SWMAAC	0.00	3	3
2008/2009 Third IA			
RTO/EMAAC	0.87	40	22
SWMAAC	0.00	3	3
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

Imports and Exports

Table 5-5 PJM capacity summary (MW): June 1, 2008, through May 31, 2012[11, 12] (See 2008 SOM, Table 5-5)

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

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

12 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.

Demand-Side Resources

Table 5-6 RPM load management and energy efficiency statistics: June 1, 2008 through May 31, 2012[13] (See 2008 SOM, Table 5-6)

	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

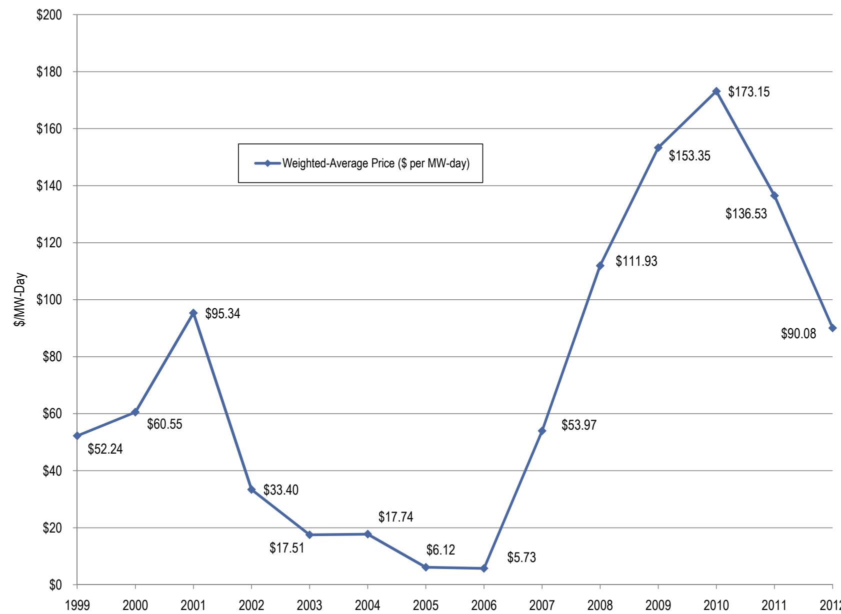
13 PJM used forecast ILR, including FRR DR, for the first four base residual auctions. For 2008/2009 and 2009/2010, certified ILR data were used in the calculation here because the certified ILR data are now available. For 2010/2011, forecast ILR less FRR DR is used and will continue to be used until 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 Performance

Table 5-7 Capacity prices: 2007/2008 through 2012/2013 RPM Auctions (See 2008 SOM, Table 5-10)

	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[14, 15] (See 2008 SOM, Figure 5-1)



14 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.

15 The 2011 weighted average price has been revised since the *2008 State of the Market Report for PJM* was posted to reflect the 2011/2012 First IA clearing.

Table 5-8 RPM cost to load: 2008/2009 through 2012/2013 RPM Auctions[16, 17, 18, 19] (See 2008 SOM, Table 5-11)

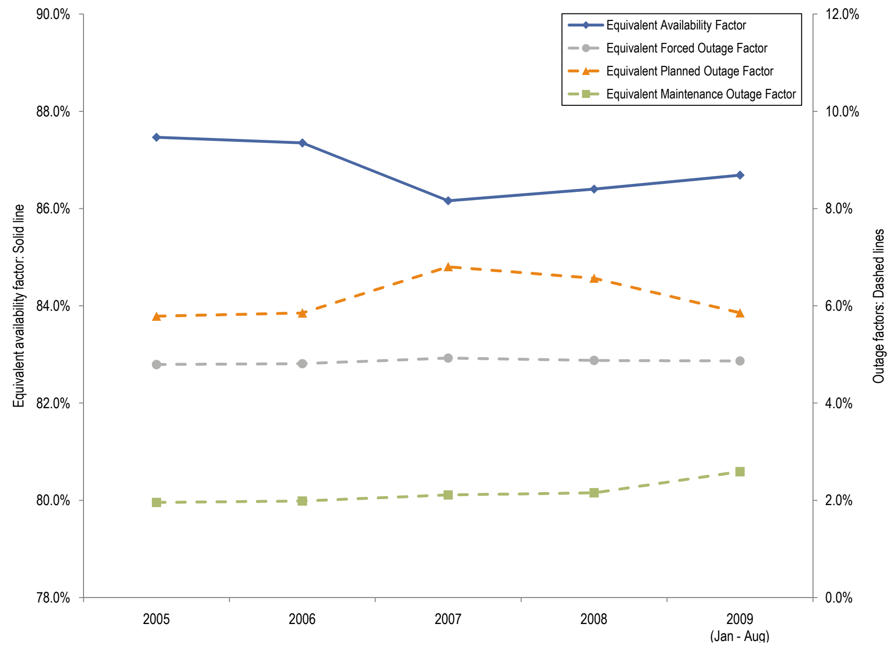
	Net Load Price ($/MW-Day)	UCAP Obligation (MW)	Annual Charges
2008/2009 BRA			
RTO	$113.22	79,814.6	$3,298,362,289
EMAAC	$145.24	35,755.4	$1,895,486,718
SWMAAC	$183.03	15,684.6	$1,047,824,603
2009/2010 BRA			
RTO	$104.82	56,696.9	$2,169,117,837
MAAC+APS	$193.78	60,984.3	$4,313,445,473
SWMAAC	$224.86	16,205.7	$1,330,043,812
2010/2011 BRA			
RTO	$174.29	129,253.2	$8,222,552,183
DPL	$178.27	4,595.0	$298,989,987
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

16 The annual charges are calculated using the rounded, net load prices as posted in the PJM Base Residual Auction results.
17 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.
18 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, 2011/2012, and 2012/2013 Net Load Prices and Obligation MW are not finalized.
19 The 2009/2010 Final Zonal UCAP Obligations and Final Zonal Capacity Prices have been updated since the *2009 Quarterly State of the Market Report for PJM: January through June* was posted, due to a PJM error with non zone load that was corrected by PJM.

Generator Performance

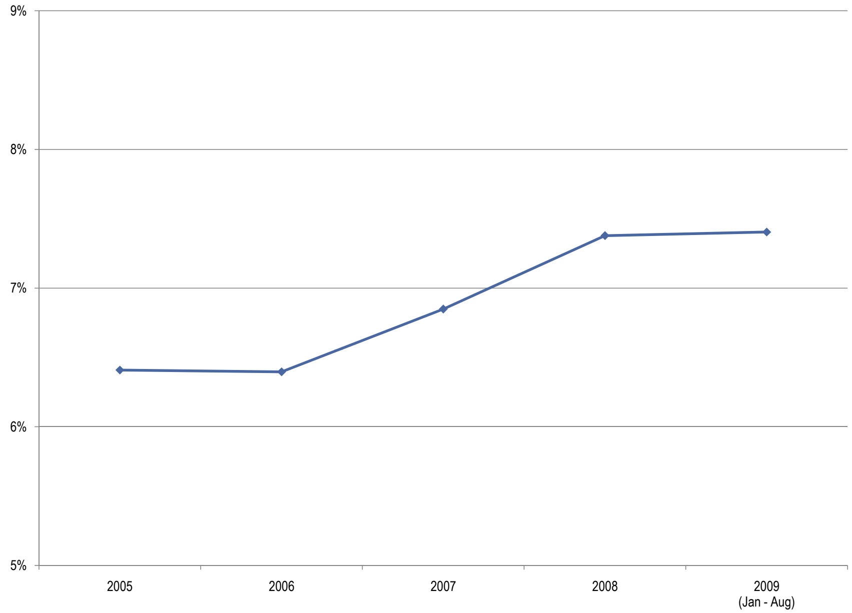
Generator Performance Factors

Figure 5-2 PJM equivalent outage and availability factors: Calendar years 2005 to 2009 (January through August) (See 2008 SOM Figure 5-7)



Generator Forced Outage Rates

Figure 5-3 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2005 to 2009 (January through August) (See 2008 SOM Figure 5-8)



Components of EFORd

Table 5-9 Contribution to EFORd by unit type (Percentage points): Calendar years 2005 to 2009 (January through August)[20] (See 2008 SOM Table 5-17)

	2004	2005	2006	2007	2008	2009 (Jan - Aug)
Combined Cycle	0.5	0.6	0.5	0.4	0.4	0.5
Combustion Turbine	1.3	1.3	1.4	1.6	1.5	1.4
Diesel	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.2	0.1	0.1	0.1	0.1	0.1
Nuclear	0.6	0.3	0.3	0.2	0.4	0.8
Steam	4.7	4.1	4.1	4.4	4.9	4.6
Total	7.3	6.4	6.4	6.8	7.4	7.4

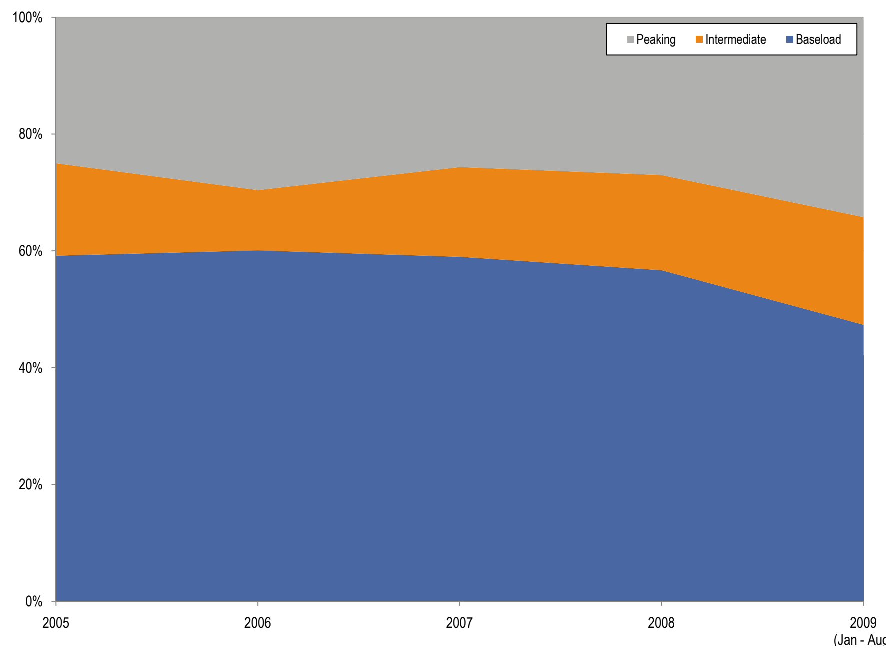
20 Calculated values presented in Section 5, "Capacity Market" at "Generator Performance" are based on unrounded, underlying data and may differ from those derived from the rounded values shown in the tables.

Table 5-10 Five-year PJM EFORd data by unit type: Calendar years 2005 to 2009 (January through August) (See 2008 SOM Table 5-19)

	2004	2005	2006	2007	2008	2009 (Jan - Aug)
Combined Cycle	5.2%	5.0%	4.3%	3.5%	3.4%	3.7%
Combustion Turbine	9.0%	8.9%	9.4%	11.1%	10.9%	8.8%
Diesel	8.9%	14.0%	13.2%	11.8%	9.6%	9.7%
Hydroelectric	3.9%	2.5%	1.9%	2.3%	2.4%	2.8%
Nuclear	3.2%	1.6%	1.4%	1.3%	1.9%	4.2%
Steam	9.2%	8.1%	8.2%	8.8%	9.8%	9.6%
Total	7.3%	6.4%	6.4%	6.8%	7.4%	7.4%

Duty Cycle and EFORd

Figure 5-4 Contribution to EFORd by duty cycle: Calendar years 2005 to 2009 (January through August) (See 2008 SOM Figure 5-9)



Forced Outage Analysis

Table 5-11 Outage cause contribution to PJM EFOF: January through August 2009 (See 2008 SOM Table 5-20)

	Percentage Point Contribution to EFOF	Contribution to EFOF
Low Pressure Turbine	0.87	17.8%
Boiler Tube Leaks	0.82	16.8%
Economic	0.46	9.5%
Electrical	0.28	5.7%
Generator	0.21	4.2%
Boiler Air and Gas Systems	0.19	3.9%
Fuel Quality	0.12	2.5%
Boiler Fuel Supply from Bunkers to Boiler	0.12	2.5%
Stack Emission	0.11	2.2%
High Pressure Turbine	0.10	2.1%
Condensing System	0.09	1.9%
Valve	0.09	1.8%
Inlet Air System and Compressors	0.08	1.7%
Controls	0.07	1.4%
Performance	0.07	1.4%
Miscellaneous (Steam Turbine)	0.07	1.4%
Miscellaneous	0.07	1.4%
Feedwater System	0.07	1.4%
Miscellaneous (Generator)	0.06	1.3%
All Other Causes	0.92	18.9%
Total	4.87	100.0%

Table 5-12 Contributions to Economic Outages: January through August 2009 (See 2008 SOM Table 5-21)

	Contribution to Economic Reasons
Lack of Fuel (OMC)	90.7%
Lack of Fuel (Non-OMC)	5.4%
Other Economic Problems	2.3%
Lack of Water (Hydro)	1.4%
Fuel Conservation	0.1%
Problems with Primary Fuel for Units with Secondary Fuel Operation	0.0%
Total	100.0%

Table 5-13 Contribution to EFOF by unit type for the most prevalent causes: January through August 2009 (See 2008 SOM Table 5-22)

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Low Pressure Turbine	0.2%	0.0%	0.0%	0.0%	77.5%	8.1%	17.8%
Boiler Tube Leaks	1.5%	0.0%	0.0%	0.0%	0.0%	23.9%	16.8%
Economic	3.4%	11.6%	4.1%	0.7%	0.0%	12.3%	9.5%
Electrical	13.4%	10.8%	0.6%	3.7%	7.9%	4.1%	5.7%
Generator	8.0%	2.7%	0.3%	61.8%	0.0%	3.4%	4.2%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	5.6%	3.9%
Fuel Quality	0.0%	0.0%	13.3%	0.0%	0.0%	3.6%	2.5%
Boiler Fuel Supply from Bunkers to Boiler	0.3%	0.0%	0.0%	0.0%	0.0%	3.5%	2.5%
Stack Emission	0.0%	0.4%	0.3%	0.0%	0.0%	3.1%	2.2%
High Pressure Turbine	0.1%	0.0%	0.0%	0.0%	0.0%	3.0%	2.1%
Condensing System	0.1%	0.0%	0.0%	0.0%	0.5%	2.7%	1.9%
Valve	1.8%	0.0%	0.0%	0.0%	1.6%	2.1%	1.8%
Inlet Air System and Compressors	12.7%	16.0%	0.0%	0.0%	0.0%	0.0%	1.7%
Controls	0.5%	1.5%	0.7%	0.8%	0.1%	1.8%	1.4%
Performance	1.2%	10.3%	4.4%	2.7%	0.1%	1.0%	1.4%
Miscellaneous (Steam Turbine)	6.0%	0.0%	0.0%	0.0%	0.0%	1.4%	1.4%
Miscellaneous	8.5%	11.8%	0.2%	0.1%	0.0%	0.3%	1.4%
Feedwater System	1.0%	0.0%	0.0%	0.0%	0.0%	1.8%	1.4%
Miscellaneous (Generator)	10.4%	1.0%	0.0%	1.2%	0.0%	0.7%	1.3%
All Other Causes	30.9%	33.8%	76.0%	28.9%	12.3%	17.5%	18.9%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-14 Contribution to EFOF by unit type: January through August 2009 (See 2008 SOM Table 5-23)

	EFOF	Contribution to EFOF
Combined Cycle	2.7%	7.0%
Combustion Turbine	1.6%	5.2%
Diesel	7.8%	0.3%
Hydroelectric	2.2%	1.8%
Nuclear	4.1%	15.7%
Steam	7.1%	69.9%
Total	4.9%	100.0%

Outages Deemed Outside Management Control

Table 5-15 PJM EFORd vs. XEFORd by unit type: January through August 2009 (See 2008 SOM Table 5-24)

	EFORd	XEFORd	Difference
Combined Cycle	3.7%	3.5%	0.2%
Combustion Turbine	8.8%	7.6%	1.2%
Diesel	9.7%	8.2%	1.5%
Hydroelectric	2.8%	2.6%	0.1%
Nuclear	4.2%	4.1%	0.0%
Steam	9.6%	8.3%	1.3%
Total	7.4%	6.6%	0.8%

Components of EFORp

Table 5-16 Contribution to EFORp by unit type (Percentage points): Calendar years 2008 to 2009 (January through August) (New Table)

	2008	2009 (Jan - Aug)
Combined Cycle	0.3	0.3
Combustion Turbine	0.4	0.4
Diesel	0.0	0.0
Hydroelectric	0.1	0.1
Nuclear	0.2	0.8
Steam	3.9	2.2
Total	4.9	3.8

Table 5-17 PJM EFORp data by unit type: Calendar years 2008 to 2009 (January through August) (New Table)

	2008	2009 (Jan - Aug)
Combined Cycle	2.4%	2.1%
Combustion Turbine	3.0%	2.4%
Diesel	5.3%	4.9%
Hydroelectric	1.7%	2.9%
Nuclear	0.8%	4.1%
Steam	7.9%	4.6%
Total	4.9%	3.8%

EFORd and EFORp

Table 5-18 Contribution to PJM EFORd and EFORp by unit type: Calendar year 2009 (January through August) (New Table)

	EFORd	EFORp	Difference
Combined Cycle	0.5	0.3	0.2
Combustion Turbine	1.4	0.4	1.0
Diesel	0.0	0.0	0.0
Hydroelectric	0.1	0.1	(0.0)
Nuclear	0.8	0.8	0.0
Steam	4.6	2.2	2.4
Total	7.4	3.8	3.6

Table 5-19 PJM EFORd and EFORp data by unit type: Calendar year 2009 (January through August) (New Table)

	EFORd	EFORp	Difference
Combined Cycle	3.7%	2.1%	1.6%
Combustion Turbine	8.8%	2.4%	6.4%
Diesel	9.7%	4.9%	4.8%
Hydroelectric	2.8%	2.9%	(0.2%)
Nuclear	4.2%	4.1%	0.1%
Steam	9.6%	4.6%	5.0%
Total	7.4%	3.8%	3.6%