MMU Analysis of the Wholesale Market Supporting New Jersey's Basic Generation Service Auction: Planning Periods 2005-2006, 2006-2007 and 2007- December 2007

Monitoring Analytics

The Independent Market Monitor for PJM

March 23, 2009

Overview

In a letter dated November 15, 2006, the New Jersey Board of Public Utilities (BPU) requested that the PJM Market Monitoring Unit (MMU) provide an assessment of the BGS auction market and the underlying wholesale power market that supports the BGS market. The BPU reiterated its request in a letter dated May 30, 2007. The BPU requested that the MMU "provide analyses comprising a comprehensive assessment of the state of the BGS auction market and the underlying wholesale market that supports the BGS market, including but not limited to market structure, market power, strategic behavior, potential mitigation measures, current market rules, current BGS auction rules and to recommend improvements that might serve to enhance the competitiveness of the BGS auction." PJM responded by letter dated August 24, 2007, stating that "the Board will direct the MMU to respond to your request."

In 2007, ongoing disagreements between senior management at PJM and the MMU about the definition of MMU independence were addressed in a FERC-mandated settlement process. The issues were resolved in a settlement that was accepted by the Commission on March 21, 2008.[1] This settlement removed the market monitoring function from PJM Interconnection, L.L.C., and housed that function in a separate corporation providing market monitoring services under a long-term contract. The settlement also established the tools available to the MMU to carry out its core functions and included revisions to the market monitoring plan intended to strengthen the independence of the MMU and clarify its role.[2] The MMU became a separate entity, organized as Monitoring Analytics, LLC, effective August 1, 2008. After August 1, 2008, the MMU is also referred to as the Independent Market Monitor for PJM (IMM).

This report is the result of the MMU's analysis of the markets in question during the 2005-2006, 2006-2007 planning periods and the June 1 through December 31, 2007 portion of the 2007-2008 planning period. This analysis is limited to an examination of PJM market structures, the behavior of participants that affected New Jersey results and the performance of the market to the extent it affects New Jersey load in the planning years in question. The MMU did not review the auction itself, nor did it review the appropriateness of the auction results in the years in question. This report covers each of the components of the wholesale electricity market: energy, ancillary, capacity (RPM) and FTR markets and the all-in-costs of wholesale electric service for each New Jersey related zone.

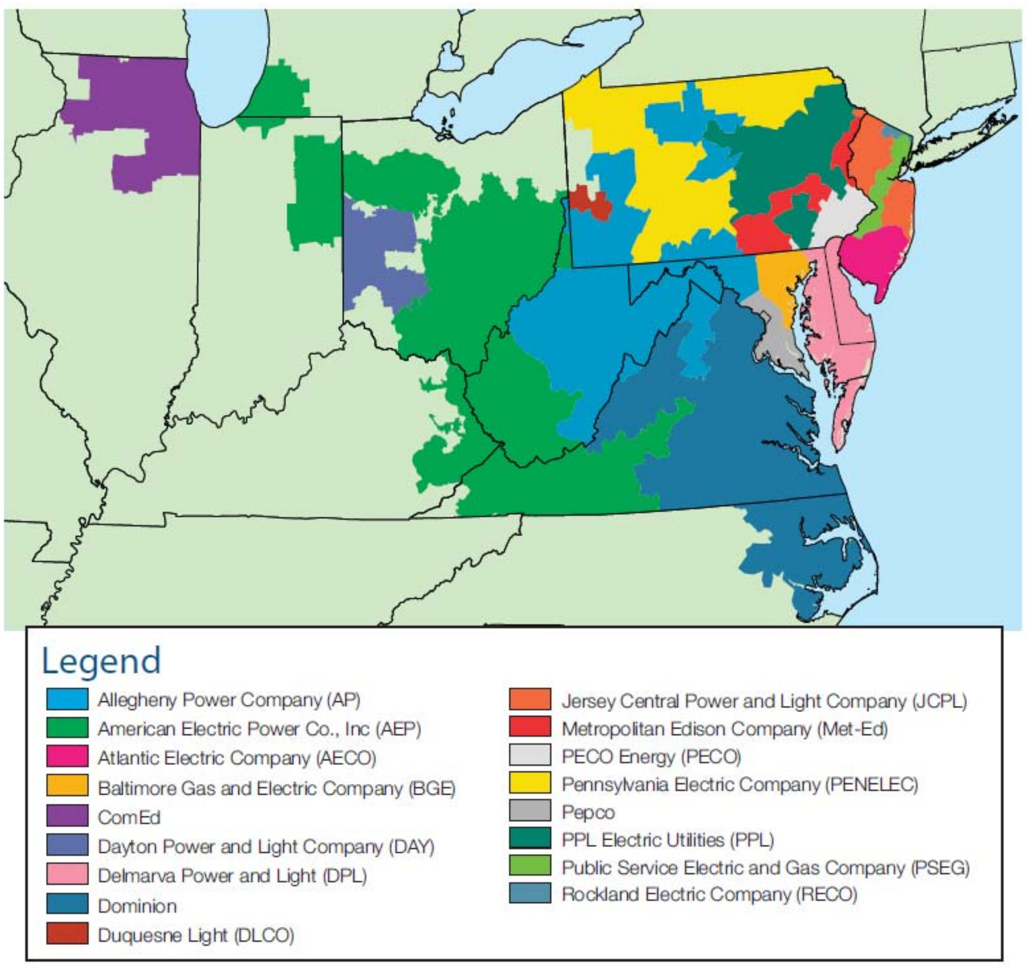
1 *Organization of PJM States, Inc., et al. v. PJM*, 122 FERC ¶61,257 (2008).

2 Attachment M of the PJM Open Access Transmission Tariff ("OATT") constitutes the Market Monitoring Plan.

Basic Generation Service (BGS) Auctions

The BGS auctions for the state of New Jersey occur every February. The BGS auction provides default service to those customers that did not choose a third party electricity supplier. There are two types of BGS auctions: Fixed Price (FP) and Commercial and Industrial Energy Price (CIEP). The BGS-FP auction meets the needs of residential and smaller commercial customers while the BGS-CIEP auction serves the needs of larger commercial and industrial customers. For the 2005 through 2007 BGS auctions, the service year has coincided with the upcoming PJM planning period. For example, during the February 2005 BGS auctions, the supply period for both the BGS-FP and BGS-CIEP auctions was from June 1, 2005 through May 31, 2006.

Figure 1 PJM's footprint and its zones



Conclusions

This report assesses the competitiveness of the PJM markets, as they affected New Jersey, during the 2005-2006, 2006-2007 planning periods and the June 1 through December 31, 2007 portion of the 2007-2008 planning period. This assessment included an examination of market structure, participant behavior and market performance. The MMU did not directly assess the competitiveness of the BGS Auction results or the auction design itself. The MMU did not examine the concentration of ownership of generation sellers to BGS providers or the associated supply contracts because the MMU did not have access to the data. Such an analysis would be a useful extension of this report. This report was prepared by and represents the analysis of the MMU.

The MMU concludes that the results of the PJM wholesale power markets were competitive, during the time periods reviewed. More specifically, the MMU concludes that in during the 2005-2006, 2006-2007 planning periods and the June 1 through December 31, 2007 portion of the 2007-2008 planning period:

- The Energy Market results were competitive, with the exception that units exempt from offer capping can and did exercise market power at times that affected LMP in New Jersey zones. FERC's decision to remove these exemptions from offer capping effective May 17, 2008 resolved this issue;

- The Capacity Market results were competitive;

- The Regulation Market results cannot be determined to have been competitive or to have been noncompetitive. The implementation of the three pivotal supplier test in the Regulation Market effective January 1, 2008 addressed this issue;[3]

- The Synchronized Reserve Markets' results were competitive; and

- The FTR Auction Market results were competitive.

[3] The Regulation Market issues were addressed by the implementation of the three pivotal supplier test effective January 1, 2008.

All-in Price of Wholesale Energy

The all-in price of wholesale energy represents the total price, per MWh, of purchasing wholesale electricity from PJM. It includes the per MWh price of energy, capacity, ancillary services and uplift charges. The all-in price of wholesale energy includes the costs associated with congestion and marginal losses. The value of ARRs and FTRs as hedges is shown as a per MWh credit. Table 1, Table 2 and Table 3 provide the all-in price per MWh of wholesale energy, by New Jersey related zone for the 2005-2006, 2006-2007 planning periods and the June 1, 2007 through December 31, 2007 portion of the 2007-2008 planning period.

AECO, JCPL, PSEG and RECO are all transmission zones related to New Jersey. The all-in price of wholesale power varies by zone. Load served in the AECO, JCPL, PSEG and RECO zones is settled at the AECO, JCPL, PSEG and RECO zonal load weighted LMPs. No load is actually settled at a New Jersey aggregate load weighted price. The New Jersey aggregate is comprised of those AECO, JCPL, PSEG and RECO load buses that are physically within the geographic boundaries of the state of New Jersey. The New Jersey results are presented for informational purposes.

Table 1 All-in price per MWh, by New Jersey related zone for June 1, 2005 through May 31, 2006

	AECO	JCPL	PSEG	RECO	NJ
Energy	$77.91	$74.21	$77.39	$77.10	$76.55
Ancillary Service	$1.55	$1.55	$1.55	$1.55	$1.55
Capacity	$0.02	$0.02	$0.02	$0.02	$0.02
Operating Reserve Charges	$0.44	$0.44	$0.44	$0.44	$0.44
DSR	$0.03	$0.00	$0.01	$0.00	$0.01
Total	$79.94	$76.21	$79.40	$79.10	$78.56
ARR Hedge	($2.13)	($0.91)	($1.91)	($0.71)	($1.63)
FTR Hedge	($0.64)	($0.53)	($0.16)	($0.03)	($0.33)
Net Total	$77.16	$74.77	$77.34	$78.36	$76.60

Table 2 All-in price per MWh, by New Jersey related zone for June 1, 2006 through May 31, 2007

	AECO	JCPL	PSEG	RECO	NJ
Energy	$63.34	$60.65	$62.57	$62.28	$62.11
Ancillary Service	$1.40	$1.40	$1.40	$1.40	$1.40
Capacity	$0.03	$0.03	$0.03	$0.03	$0.03
Operating Reserve Charges	$0.24	$0.24	$0.24	$0.24	$0.24
DSR	$0.01	$0.00	$0.02	$0.00	$0.01
Total	$65.02	$62.32	$64.26	$63.95	$63.79
ARR Hedge	($3.26)	($1.55)	($2.51)	($0.92)	($2.30)
FTR Hedge	($0.22)	($0.42)	($0.26)	$0.00	($0.29)
Net Total	$61.54	$60.36	$61.49	$63.03	$61.19

Table 3 All-in cost per MWh, by New Jersey related zone for June 1, 2007 through December 31, 2007

	AECO	JCPL	PSEG	RECO	NJ
Energy	$77.32	$77.69	$74.57	$75.19	$75.86
Ancillary Service	$1.47	$1.47	$1.47	$1.47	$1.47
Capacity	$15.20	$16.40	$14.79	$16.79	$15.36
Operating Reserve Charges	$0.34	$0.34	$0.34	$0.34	$0.34
DSR	$0.01	$0.09	$0.01	$0.00	$0.04
Total	$94.34	$95.99	$91.19	$93.79	$93.06
ARR Hedge	($2.22)	($1.37)	($2.57)	($1.16)	($2.15)
FTR Hedge	($0.33)	($0.93)	($0.33)	$0.00	($0.50)
Net Total	$91.79	$93.69	$88.28	$92.63	$90.41

Energy Market

The PJM Energy Market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Energy Markets, bilateral and forward markets and self-supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Markets. These markets provide key benchmarks against which market participants may measure results of transactions in other markets.

The MMU analyzed measures of market structure, participant conduct and market performance during the 2005-2006, 2006-2007 planning periods and the June 1 through December 31, 2007 portion of the 2007-2008 planning period, including market size, concentration, residual supply index, price-cost markup, net revenue and price. The MMU concludes that the PJM Energy Market results were competitive, with the exception that units exempt from offer capping can and did exercise market power at times that affected LMP in New Jersey zones in the 2005-2006, 2006-2007 and 2007-through December 2007 planning periods. FERC's decision to remove these exemptions from offer capping in May of 2008 has resolved this issue.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[4] PJM's market power mitigation goals have focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.

Market Structure

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for constraints not exempt from offer capping. This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test, as implemented, is consistent with the United States Federal Energy Regulatory Commission's (FERC's) market power tests, encompassed under the delivered price test. The three pivotal supplier test is an application of the delivered price test to both the Real-Time Market and hourly Day-Ahead Market. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests.

The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test

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4 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment M: Market Monitoring Plan," Third Revised Sheet No. 452 (Effective July 17, 2006).

demonstrates that it is working successfully to offer cap owners only when the local market structure is noncompetitive.

Local Market Structure and Offer Capping

PJM's three pivotal supplier test represents the practical application of the FERC market power tests in real time.[5] The three pivotal supplier test is passed if no three generation suppliers in a load pocket are jointly pivotal. Stated another way, if the incremental output of the three largest suppliers in a load pocket is removed and enough incremental generation remains available to solve the incremental demand for constraint relief, where the relevant competitive supply includes all incremental MW at a cost less than, or equal, to 1.5 times the clearing price, then offer capping is suspended.

The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required to prevent the exercise of local market power for any constraint not exempt from offer capping.

The MMU analyzed the results of the three pivotal supplier tests conducted by PJM for the Real-Time Energy Market for the period 2006/2007 and the period June 2007 through December of 2007.[6] Table 4 and Table 6 show the results of the three pivotal supplier test for the top 15 constraints impacting the New Jersey real-time load congestion costs, for the period 2006/2007 and the period June 2007 through December of 2007. Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case.[7] The number of hours in which one or more suppliers pass the three pivotal supplier test and are exempt from offer capping increases as the number of suppliers in the local market increases. Table 6, Table 5 and Table 7 provide additional information regarding each of the top fifteen constraints including the average MW required to relieve a constraint, the average supply available, the average number of owners included in each test and the average number of owners that passed or failed each test, for the period 2006/2007 and the period June 2007 through December of 2007.

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

[6] The three pivotal supplier test was implemented in March of 2006.

[7] The three pivotal supplier test in the Real-Time Energy Market is applied by PJM as necessaryand may be applied multiple times within a single hour for a specific constraint. Each application of the test is done in a five-minute interval.

Table 4 Three pivotal supplier results summary for the top 15 constraints impacting New Jersey congestion costs: June 1, 2006 to May 31, 2007

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Bedington - Black Oak	Peak	2,990	2,413	81%	962	32%
	Off peak	5,126	4,499	88%	1,219	24%
Cloverdale - Lexington	Peak	1,766	1,209	68%	907	51%
	Off peak	7,291	4,855	67%	4,031	55%
5004/5005 Interface	Peak	962	804	84%	263	27%
	Off peak	275	235	85%	81	29%
West	Peak	1,231	1,210	98%	46	4%
	Off peak	780	731	94%	83	11%
Wylie Ridge	Peak	1,326	856	65%	623	47%
	Off peak	1,712	1,277	75%	696	41%
Branchburg - Flagtown	Peak	487	9	2%	486	100%
	Off peak	39	1	3%	39	100%
South Mahwah - Waldwick	Peak	147	0	0%	147	100%
	Off peak	53	0	0%	53	100%
Mount Storm - Pruntytown	Peak	628	515	82%	199	32%
	Off peak	1,256	977	78%	509	41%
Laurel - Woodstown	Peak	1,173	0	0%	1,173	100%
	Off peak	536	0	0%	536	100%
AP South	Peak	350	214	61%	178	51%
	Off peak	184	106	58%	102	55%
Kammer	Peak	922	779	84%	265	29%
	Off peak	1,203	958	80%	381	32%
Loudoun - Morrisville	Peak	370	206	56%	224	61%
	Off peak	28	20	71%	13	46%
Muskingum River - Ohio Central	Peak	157	0	0%	157	100%
	Off peak	0	0	0%	0	0%
Edison - Meadow Rd	Peak	1,408	0	0%	1,408	100%
	Off peak	191	0	0%	191	100%
Whitpain	Peak	222	60	27%	193	87%
	Off peak	332	11	3%	331	100%

Table 5 Three pivotal supplier test details for the top 15 constraints impacting New Jersey congestion costs: June 1, 2006 to May 31, 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Bedington - Black Oak	Peak	58	229	12	9	3
	Off peak	61	245	11	9	2
Cloverdale - Lexington	Peak	109	336	17	10	6
	Off peak	97	276	14	8	6
5004/5005 Interface	Peak	110	403	18	15	3
	Off peak	104	373	17	14	3
West	Peak	153	80	18	18	0
	Off peak	167	73	17	16	1
Wylie Ridge	Peak	42	123	14	11	4
	Off peak	45	150	16	11	5
Branchburg - Flagtown	Peak	33	31	4	0	4
	Off peak	35	28	3	0	3
South Mahwah - Waldwick	Peak	16	18	3	0	3
	Off peak	13	27	3	0	3
Mount Storm - Pruntytown	Peak	116	398	13	10	3
	Off peak	125	376	11	8	3
Laurel - Woodstown	Peak	2	6	1	0	1
	Off peak	2	7	1	0	1
AP South	Peak	100	17	17	10	7
	Off peak	76	17	16	9	7
Kammer	Peak	95	356	19	15	4
	Off peak	80	305	16	12	4
Loudoun - Morrisville	Peak	123	283	23	12	11
	Off peak	99	280	21	14	7
Muskingum River - Ohio Central	Peak	45	36	2	0	2
	Off peak	0	0	0	0	0
Edison - Meadow Rd	Peak	7	53	1	0	1
	Off peak	6	53	1	0	1
Whitpain	Peak	24	48	6	1	5
	Off peak	35	25	5	0	5

Table 6 Three pivotal supplier results summary for the top 15 constraints impacting New Jersey congestion costs: June 1, 2007 to December 31, 2007

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Branchburg - Readington	Peak	1,233	152	12%	1,217	99%
	Off peak	458	20	4%	456	100%
Atlantic - Larrabee	Peak	748	231	31%	710	95%
	Off peak	870	18	2%	868	100%
Kammer	Peak	1,384	1,225	89%	305	22%
	Off peak	3,507	2,911	83%	1,149	33%
West	Peak	895	848	95%	96	11%
	Off peak	880	833	95%	97	11%
5004/5005 Interface	Peak	630	559	89%	156	25%
	Off peak	237	197	83%	71	30%
Cloverdale - Lexington	Peak	1,342	1,002	75%	646	48%
	Off peak	5,956	4,001	67%	3,191	54%
AP South	Peak	982	729	74%	399	41%
	Off peak	1,010	721	71%	466	46%
Branchburg - Flagtown	Peak	178	0	0%	178	100%
	Off peak	90	0	0%	90	100%
Beckett - Paulsboro	Peak	885	0	0%	885	100%
	Off peak	277	0	0%	277	100%
Sammis - Wylie Ridge	Peak	234	139	59%	129	55%
	Off peak	1,222	883	72%	571	47%
Brunner Island - Yorkana	Peak	322	194	60%	189	59%
	Off peak	230	105	46%	194	84%
Wylie Ridge	Peak	650	265	41%	405	62%
	Off peak	896	658	73%	337	38%
Elrama - Mitchell	Peak	905	215	24%	856	95%
	Off peak	1,992	416	0%	1,899	0%
Conastone	Peak	206	121	59%	112	54%
	Off peak	3	3	100%	0	0%
East Towanda	Peak	3,174	49	2%	3,159	100%
	Off peak	794	1	0%	794	100%

Table 7 Three pivotal supplier test details for the top 15 constraints impacting New Jersey congestion costs: June 1, 2007 to December 31, 2007

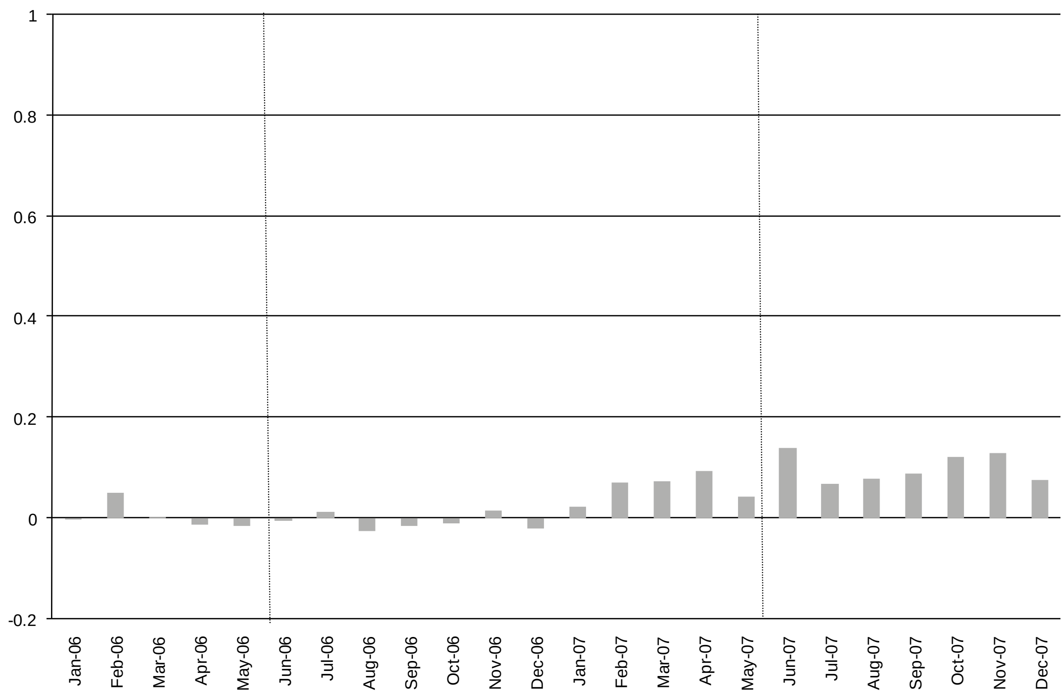
Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Branchburg - Readington	Peak	21	41	4	0	4
	Off peak	18	41	3	0	3
Atlantic - Larrabee	Peak	23	41	5	1	4
	Off peak	24	31	3	0	3
Kammer	Peak	76	336	19	16	3
	Off peak	66	287	15	11	3
West	Peak	131	94	18	17	1
	Off peak	127	72	17	16	1
5004/5005 Interface	Peak	108	414	21	17	3
	Off peak	102	363	17	14	3
Cloverdale - Lexington	Peak	91	329	16	11	5
	Off peak	92	277	14	8	6
AP South	Peak	89	20	16	12	5
	Off peak	91	18	15	10	5
Branchburg - Flagtown	Peak	24	24	3	0	3
	Off peak	26	4	3	0	3
Beckett - Paulsboro	Peak	5	5	1	0	1
	Off peak	2	6	1	0	1
Sammis - Wylie Ridge	Peak	53	137	16	9	7
	Off peak	54	140	15	10	6
Brunner Island - Yorkana	Peak	28	74	12	8	4
	Off peak	32	65	9	5	5
Wylie Ridge	Peak	31	101	9	8	1
	Off peak	58	186	16	12	4
Elrama - Mitchell	Peak	28	71	5	1	4
	Off peak	28	50	5	1	4
Conastone	Peak	55	94	15	9	5
	Off peak	25	106	18	18	0
East Towanda	Peak	15	4	3	0	3
	Off peak	7	4	3	0	3

Market Conduct – Unit Markup

The price-cost markup index is a measure of conduct or behavior by the owners of generating units within the PJM footprint and not a measure of market impact. For marginal units, the markup index is a measure of market power. For units not on the margin, the markup index is a measure of the intent to exercise market power or, in cases where the markup results in higher-priced units replacing lower-priced units in the dispatch, also a measure of market power. A positive markup by marginal units results in a difference between the observed market price and the competitive market price. The goal of the markup analysis is both to calculate the actual markups by marginal units (market conduct) and to estimate the impact of those markups on the difference between the observed market price and the competitive market price (market impact or market performance). The results must be interpreted carefully, however, because the impact assumes that the same units are marginal and the impact is not based on a redispatch of the system.

Figure 2 shows the load-weighted, unit markup index for the PJM wholesale real time energy market. The markup index for each marginal unit is calculated as (Price – Cost)/Price. The markup index is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost. This index calculation method weights the impact of individual unit markups using sensitivity factors. In 2007, the annual average markup index was 0.09 with a maximum of 0.22 in June and a minimum of 0.03 in January. The annual average markup index was higher than in 2006. In 2006, the annual average markup index was 0.00 with a maximum of 0.05 in February and a minimum of -0.02 in August.

Figure 2 Load-weighted unit markup index: Calendar years 2006 to 2007



Market Performance – Markup

The markup index is a summary measure of the behavior or conduct of individual marginal units. However the markup conduct measure does not explicitly capture the impact of this behavior on market prices. As an example, if unit A has a $90 cost and a $100 price, while unit B has a $9 cost and a $10 price, both would show a markup of 10 percent, but the price impact of unit A's markup at the generator bus would be $10 while the price impact of unit B's markup at the generator bus would be $1. Depending on each unit's location on the transmission system, those bus-level impacts could also translate to different impacts on total system price.

The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. These measures include the impact of markup on system prices and the impact of markup on zonal prices. In addition, the impact of the markup of specific subsets of units on system and zonal prices is analyzed, including units exempt from offer capping, units on high-load days and frequently mitigated units.

In each case, the calculation shows the markup component of price based on a comparison between the price-based offer and the cost-based offer of each actual marginal unit on the system. The calculation is not based on a redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at marginal cost. Thus the results do not reflect a counterfactual market outcome based on the assumption that all units made all offers at marginal cost. It is important to note that a full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on marginal cost and actual dispatch. It is possible that the unit-specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

The MMU calculates explicit measures of the impact of marginal unit markups on LMP. The price impact of markup must be interpreted carefully. The price impact is not based on a full redispatch of the system, but such a full redispatch is practically impossible as it would require reconsideration of all dispatch decisions and unit commitments. The markup impact includes the maximum impact of the identified markup conduct on a unit-by-unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the Energy Market.

Since unit sensitivity factors are not available prior to 2006, the markup components calculations of load weighted LMP are limited to three periods: January 1, 2006 to May 31, 2006; June 1, 2006 through May 31, 2007; and June 1, 2007 to December 31, 2007.

Markup Components

The price component measure uses load-weighted, price-based LMP and load-weighted LMP computed using cost-based offers for all marginal units. The price component of markup is computed by calculating the system and zonal prices, based on the price-based offers of the marginal units and comparing that to the system and zonal prices, based on the cost-based offers of the marginal units. These results are compared to the actual system and zonal prices to determine how much of the LMP can be attributed to markup. Note that markup on high-load days is likely to be the result of appropriate scarcity pricing rather than market power. The price impact of markup must be interpreted carefully. The markup impact includes the maximum impact of the identified markup conduct on a unit-by-unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval.

Markup Components of Price: Summary Statistics

The following tables (Table 8, Table 9, and Table 10) show the markup component of average prices and of average on-peak and off-peak prices for the AECO, JCPL, PSEG, and RECO zones, the state of New Jersey and the PJM system for each period: January 1, 2006 to May 31, 2006; June 1, 2006 through May 31, 2007; and June 1, 2007 to December 31, 2007.

Table 8 Annual average markup component (Dollars per MWh) from January 2006 through May 2006

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	$0.15	$0.98	($0.69)
JCPL	$0.20	$1.09	($0.78)
PSEG	$0.86	$2.07	($0.47)
RECO	$1.15	$2.33	($0.25)
New Jersey	$0.59	$1.66	($0.58)
PJM	$0.53	$1.41	($0.38)

Table 9 Annual average markup component (Dollars per MWh) from June 2006 through May 2007

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	$3.47	$5.89	$0.91
JCPL	$3.78	$6.30	$0.93
PSEG	$3.99	$6.63	$1.03
RECO	$4.36	$6.98	$1.16
New Jersey	$3.90	$6.50	$1.00
PJM	$3.28	$5.47	$0.93

Table 10 Annual average markup component (Dollars per MWh) from June 2007 through December 2007

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	$7.54	$10.67	$4.18
JCPL	$7.90	$10.99	$4.37
PSEG	$8.01	$11.19	$4.46
RECO	$8.15	$10.95	$4.72
New Jersey	$7.95	$11.10	$4.42
PJM	$6.55	$9.44	$3.43

Exempt Unit Markup

In its May 16, 2008, order, FERC granted the request to remove PJM's market rule provisions that exempt certain generation resources from energy offer price mitigation. [8] Exemptions were removed effective May 17, 2008. Prior to this order, and during the time period examined in this study, PJM's offer-capping rules provided that specific units were exempt from offer capping, based on their date of construction. During 2005, two orders issued by the FERC modified the rules governing exemptions from the offer-capping rules. In the January 25, 2005, order, the FERC found "that the exemption for post-1996 units from the offer-capping rules is unjust and unreasonable under section 206 of the Federal Power Act and that the just and reasonable practice under section 206 is to terminate the exemption, with provisions to grandfather units for which construction commenced in reliance on the exemption."[9] The FERC noted, however, that grandfathered units would "still be subject to mitigation in the event that PJM or its market monitor concludes that these units exercise significant market power."[10] In the July 5, 2005, order, the FERC modified the dates governing unit exemptions by zone.[11] The effect of these orders was to reduce the number of units exempt from local market power mitigation rules from 215 to 56 as of the end of 2005 and that number did not change in 2006 or in 2007.

[8] 123 FERC ¶ 61,169 (2008)

[9] 110 FERC ¶ 61,053 (2005).

[10] 110 FERC ¶ 61,053 (2005).

[11] 112 FERC ¶ 61,031 (2005).

The MMU calculated the impact on system prices of exempt and non-exempt marginal unit price-cost markup, based on analysis using sensitivity factors. Since unit sensitivity factors are not available prior to 2006, the markup components calculations of load weighted LMP are calculated for three periods: January 1, 2006 to May 31, 2006; June 1, 2006 through May 31, 2007; and June 1, 2007 to December 31, 2007. The tables in the following sections compare the markup components of price of exempt and non-exempt units by zone and period. This analysis does not address whether these units would have been offer capped had they not been exempt and therefore does not address how much the contribution to LMP would have changed if the exemption had been removed. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the Energy Market.

Exempt units can and did exercise market power, at times, that would not have been permitted if the units had not been exempt. Of the 56 generators that were exempt from offer capping: 32 were marginal in the January 1, 2006 to May 31, 2006 period; 42 were marginal in the June 1, 2006 through May 31, 2007 period; and 42 were marginal in the June 1, 2007 to December 31, 2007 period. In all three periods, exempt units contributed a disproportionate amount of markup related impacts on LMP, relative to non-exempt units, in New Jersey and New Jersey related zones. For example, in the June 1, 2006 through May 31, 2007 period the 42 marginal exempt units, 6 percent of the marginal units in the period, accounted for $.76, 29 percent, of the total markup component of LMP in the period. The average markup per exempt unit was about four times higher than for non-exempt units, and the average markup for the top eight exempt units was about 21 times higher than for non-exempt units. Based on these measures it can be concluded that exempt units did exercise local market power in New Jersey during the time periods covered in this analysis. This issue has been resolved by FERC’s decision to remove the exemptions from offer capping.

Exempt Unit Markup: Summary Statistics

The following tables (Table 11, Table 12, and Table 13) show the exempt and non-exempt markup component of average prices for the AECO, JCPL, PSEG, and RECO zones, the state of New Jersey and the PJM system for each period: January 1, 2006 to May 31, 2006; June 1, 2006 through May 31, 2007; and June 1, 2007 to December 31, 2007.

Table 11 Comparison of annual exempt and non-exempt markup component (Dollars per MWh) from January 2006 through May 2006

Aggregate	Exempt Markup Component	Non-exempt Markup Component	Exempt Unit Count	Non-exempt Unit Count
AECO	$0.57	($0.42)	32	474
JCPL	$0.56	($0.36)	32	474
PSEG	$0.55	$0.31	32	474
RECO	$0.57	$0.59	32	474
New Jersey	$0.55	$0.03	32	474
PJM	$0.41	$0.12	32	474

Table 12 Comparison of annual exempt and non-exempt markup component (Dollars per MWh) from June 2006 through May 2007

Aggregate	Exempt Markup Component	Non-exempt Makup Component	Exempt Unit Count	Non-exempt Unit Count
AECO	$0.80	$2.67	42	676
JCPL	$0.84	$2.94	42	676
PSEG	$0.72	$3.28	42	676
RECO	$0.68	$3.68	42	676
New Jersey	$0.76	$3.14	42	676
PJM	$0.63	$2.65	42	676

Table 13 Comparison of annual exempt and non-exempt markup component (Dollars per MWh) from June 2007 through December 2007

Aggregate	Exempt Markup Component	Non-exempt Markup Component	Exempt Unit Count	Non-exempt Unit Count
AECO	$2.11	$5.43	42	669
JCPL	$2.36	$5.54	42	669
PSEG	$2.13	$5.88	42	669
RECO	$2.07	$6.08	42	669
New Jersey	$2.19	$5.76	42	669
PJM	$1.85	$4.70	42	669

Frequently Mitigated Units and Associated Units – Cost Impact

In the second half of 2005, discussions were held regarding scarcity pricing and local market power mitigation that led to a settlement agreement accepted by the FERC on January 27, 2006.[12] The settlement agreement revised the definition of FMUs to provide for a set of graduated adders associated with increasing levels of offer capping.[13] Units capped for 60 percent or more of their run hours and less than 70 percent are entitled to an adder of either 10 percent of their cost-based offer or $20 per MWh. Units capped 70 percent or more of their run hours and less than 80 percent are entitled to an adder of either 15 percent of their cost-based offer (not to exceed $40) or $30 per MWh. Units capped 80 percent or more of their run hours are entitled to an adder of $40 per MWh or the unit-specific, going-forward costs of the affected unit as a cost-based offer.[14] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.

The settlement agreement further amended the OA to designate associated units (AUs), also at the recommendation of the MMU. An AU is a unit that is electrically and economically identical to an FMU, but does not qualify for the same adder based on its offer capped hours. The settlement agreement provides for monthly designation of FMUs and AUs, where a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[15]

For example, if a generating station had two identical units, one of which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier 3 FMU. If the second unit were capped for 30 percent of its run hours, that unit would be an AU and receive the same Tier 3 adder as the FMU at the site, to ensure that the associated unit is not dispatched in place of the FMU, resulting in no effective adder for the FMU. In the absence of the AU designation, the associated unit would be an FMU after its dispatch and the FMU would be dispatched in its place after losing its FMU designation.

As another example, if a generating station had two identical units, one of which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier 3 FMU. If the second unit were capped for 72 percent of its run hours, that unit

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12 114 FERC ¶ 61, 076 (2006).

13 *PJM Interconnection, L.L.C.*, Settlement Agreement, Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).

14 OA, Fifth Revised Sheet No. 131B (Effective July 3, 2007).

15 OA, Fifth Revised Sheet No. 132 (Effective July 3, 2007). In 2007, the FERC approved OA revisions to clarify the AU criteria.

would be eligible for a Tier 2 FMU adder. However, the second unit is an AU to the first unit and would, therefore, be eligible for the higher Tier 3 adder.

The following sections provide the impact of the offer-cap adders for frequently mitigated units and associated units on LMP in each zone. The impact is calculated, using sensitivity factors, by comparing the actual LMP to what the LMP would have been in the absence of the FMU and AU adders. Since unit sensitivity factors do not exist prior to 2006, the impact calculations are limited to three periods: January 1, 2006 to May 31, 2006; June 1, 2006 through May 31, 2007; and June 1, 2007 to December 31, 2007. The zone impact analysis reflects where the price impact occurs, not the location of the FMUs or AUs. The additional energy cost is the affected load multiplied by the locational price impacts. The MMU calculates explicit measures of the impact of the FMU and AU adders on LMP. The price impact must be interpreted carefully. The price impact includes the maximum impact of the FMU and AU adders.

FMU and AU Cost Impact: Summary Statistics

The following tables (Table 14, Table 15, and Table 16) provide the load weighted average impact of the offer-cap adders for frequently mitigated units and associated units on LMP in the AECO, JCPL, PSEG, and RECO zones, the state of New Jersey and the PJM system for each period: January 1, 2006 to May 31, 2006; June 1, 2006 through May 31, 2007; and June 1, 2007 to December 31, 2007.

Table 14 Cost impact of FMUs and AUs (Dollars per MWh) from January 2006 through May 2006

	FMU and AU Marginal Energy Impacts (Millions)	Total Energy Cost (Millions)	Percent	LMP Impact
AECO	$1.58	$254.44	0.62%	$0.37
JCPL	$0.90	$520.53	0.17%	$0.10
PSEG	$1.57	$1,046.88	0.15%	$0.09
RECO	$0.05	$33.21	0.14%	$0.08
New Jersey	$4.11	$1,855.33	0.22%	$0.13
PJM	$33.17	$14,522.82	0.23%	$0.12

Table 15 Cost impact of FMUs and AUs (Dollars per MWh) from June 2006 through May 2007

	FMU and AU Marginal Energy Impacts (Millions)	Total Energy Cost (Millions)	Percent	LMP Impact
AECO	$18.63	$737.52	2.53%	$1.60
JCPL	$11.76	$1,506.48	0.78%	$0.47
PSEG	$18.33	$2,968.52	0.62%	$0.39
RECO	$0.44	$97.98	0.45%	$0.28
New Jersey	$49.11	$5,310.53	0.92%	$0.57
PJM	$295.99	$39,443.83	0.75%	$0.42

Table 16 Cost impact of FMUs and AUs (Dollars per MWh) from June 2007 through December 2007

	FMU and AU Marginal Energy Impacts (Millions)	Total Energy Cost (Millions)	Percent	LMP Impact
AECO	$19.32	$549.89	3.51%	$2.72
JCPL	$16.36	$1,182.15	1.38%	$1.08
PSEG	$24.43	$2,157.85	1.13%	$0.84
RECO	$0.82	$74.06	1.10%	$0.83
New Jersey	$60.93	$3,964.00	1.54%	$1.17
PJM	$319.05	$27,294.90	1.17%	$0.75

Market Performance: Load and LMP

The following section provides information on New Jersey day ahead and real time load and LMP. The New Jersey aggregate used to provide state specific day ahead and real time load and LMP is comprised of those AECO, JCPL, PSEG and RECO load buses that are physically within the geographic boundaries of the state of New Jersey. No load is actually settled at a New Jersey aggregate load weighted price.

Load

Real-Time Load

New Jersey real-time load is the total hourly real time accounting load for buses within the state of New Jersey.[16]

New Jersey Real-Time, Average Load

Table 17 presents summary real-time New Jersey state load statistics for the three planning periods: June 1, 2005 to May 31, 2006; June 1, 2006 to May 31, 2007; June 1, 2007 to December 31, 2007. This average load was based on the New Jersey hourly accounting load. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load because of the implementation of marginal loss pricing.

Table 17 New Jersey state real-time average load: June 1, 2005 to December 31, 2007

	New Jersey Real-Time Load (MWh)			Year-to-Year Change		
Planning Period	Average	Median	Standard Deviation	Average	Median	Standard Deviation
Jun 1, 2005 - May 31, 2006	9,889	9,500	2,454	NA	NA	NA
Jun 1, 2006 - May 31, 2007	9,760	9,506	2,312	(1.3%)	0.1%	(5.8%)
Jun 1, 2007 - Dec 31, 2007	10,172	9,754	2,475	4.2%	2.6%	7.1%

Zonal Real-Time, Average Load

Table 18 presents zonal real-time average load for zones related to New Jersey for the three planning periods: June 1, 2005 to May 31, 2006; June 1, 2006 to May 31, 2007; June 1, 2007 to December 31, 2007.

Table 18 Zonal real-time average load (MWh): June 1, 2005 to December 31, 2007

	AECO	JCPL	PSEG	RECO
Jun 1, 2005 - May 31, 2006	1,341	2,851	5,516	179
Jun 1, 2006 - May 31, 2007	1,329	2,835	5,416	180
Jun 1, 2007 - Dec 31, 2007	1,385	2,962	5,633	192

16 See the *2007 State of the Market Report*, Volume II, Appendix I, "Load Definitions," for detailed definitions of accounting load.

Day-Ahead Load

In the PJM Day-Ahead Energy Market, three types of financially binding demand bids are made and cleared:

- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A decrement bid is a financial bid that can be submitted by any market participant.

New Jersey state day-ahead load is the hourly total of the above three types of cleared demand bids.

New Jersey Day-Ahead, Average Load

Table 19 presents summary day-ahead load statistics for the three planning periods: June 1, 2005 to May 31, 2006; June 1, 2006 to May 31, 2007; June 1, 2007 to December 31, 2007.

Table 19 New Jersey state day-ahead average load: June 1, 2005 to December 31, 2007

	New Jersey Day-Ahead Load (MWh)			Year-to-Year Change		
Planning Period	Average	Median	Standard Deviation	Average	Median	Standard Deviation
Jun 1, 2005 - May 31, 2006	10,186	9,878	2,418	NA	NA	NA
Jun 1, 2006 - May 31, 2007	9,944	9,684	2,340	(2.4%)	(2.0%)	(3.2%)
Jun 1, 2007 - Dec 31, 2007	10,292	9,881	2,494	3.5%	2.0%	6.6%

Zonal Day-Ahead, Average Load

Table 20 presents zonal day-ahead average load for zones related to New Jersey for the three planning periods: June 1, 2005 to May 31, 2006; June 1, 2006 to May 31, 2007; June 1, 2007 to December 31, 2007.

Table 20 Zonal day-ahead average load (MWh): June 1, 2005 to December 31, 2007

Planning Period	AECO	JCPL	PSEG	RECO
Jun 1, 2005 - May 31, 2006	1,132	3,232	5,652	170
Jun 1, 2006 - May 31, 2007	1,198	3,155	5,422	170
Jun 1, 2007 - Dec 31, 2007	1,320	3,225	5,570	177

Locational Marginal Price (LMP)

The conduct of individual market entities within a market structure is reflected in market prices. The overall level of prices is a good general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them.[17]

Real-Time LMP

New Jersey Real-time LMP is the state hourly LMP for the PJM Real-Time Energy Market.

Real-Time Average LMP

New Jersey Real-Time, Average LMP

Table 21 shows the New Jersey real-time, simple average LMP for the three planning periods: June 1, 2005 to May 31, 2006; June 1, 2006 to May 31, 2007; June 1, 2007 to December 31, 2007.

Table 21 New Jersey real-time, simple average LMP (Dollars per MWh): June 1, 2005 to December 31, 2007

Planning Period	Real-Time LMP	Year-to-Year Change
Jun 1, 2005 - May 31, 2006	$69.73	NA
Jun 1, 2006 - May 31, 2007	$56.27	(19.3%)
Jun 1, 2007 - Dec 31, 2007	$69.22	23.0%

Zonal Real-Time, Average LMP

Table 22 shows zonal real-time, simple average LMP related to New Jersey for the three planning periods: June 1, 2005 to May 31, 2006; June 1, 2006 to May 31, 2007; June 1, 2007 to December 31, 2007.

17 See the *2007 State of the Market Report*, Volume II, Appendix C, "Energy Market," for methodological background, detailed price data and comparisons and Appendix H, "Calculating Locational Marginal Price" for more information on how bus LMPs are aggregated to system LMPs.

Table 22 Zonal real-time, simple average LMP (Dollars per MWh): June 1, 2005 to December 31, 2007

Planning Period	AECO	JCPL	PSEG	RECO
Jun 1, 2005 - May 31, 2006	$70.25	$66.50	$71.21	$69.51
Jun 1, 2006 - May 31, 2007	$56.51	$54.24	$57.20	$55.86
Jun 1, 2007 - Dec 31, 2007	$69.18	$70.13	$68.68	$67.97

Real-Time, Load-Weighted, Average LMP

Higher demand (load) generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than simple average prices. Load-weighted LMP reflects the average LMP paid for actual MWh consumed during a year. Load-weighted, average LMP is the average of PJM hourly LMPs, each weighted by the PJM total hourly load.

New Jersey Real-Time, Load-Weighted, Average LMP

Table 23 shows the New Jersey real-time, load-weighted, average LMP for the three planning periods: June 1, 2005 to May 31, 2006; June 1, 2006 to May 31, 2007; June 1, 2007 to December 31, 2007.

Table 23 New Jersey real-time, load-weighted, average LMP (Dollars per MWh): June 1, 2005 to December 31, 2007

	New Jersey	
Planning Period	Real-Time Load-Weighted LMP	Year-to-Year Change
Jun 1, 2005 - May 31, 2006	$76.55	NA
Jun 1, 2006 - May 31, 2007	$62.11	(18.9%)
Jun 1, 2007 - Dec 31, 2007	$75.86	22.1%

Zonal Real-Time, Load-Weighted, Average LMP

Table 24 shows zonal real-time, load-weighted, average LMP related to New Jersey for the three planning periods: June 1, 2005 to May 31, 2006; June 1, 2006 to May 31, 2007; June 1, 2007 to December 31, 2007.

Table 24 Zonal real-time, load-weighted, average LMP (Dollars per MWh): June 1, 2005 to December 31, 2007

Planning Period	AECO	JCPL	PSEG	RECO
Jun 1, 2005 - May 31, 2006	$77.91	$74.21	$77.39	$77.10
Jun 1, 2006 - May 31, 2007	$63.34	$60.65	$62.57	$62.28
Jun 1, 2007 - Dec 31, 2007	$77.32	$77.69	$74.57	$75.19

Day-Ahead LMP

New Jersey Day-ahead LMP is the hourly state LMP for the PJM Day-Ahead Energy Market.

Day-Ahead Average LMP

New Jersey Day-Ahead, Annual Average LMP

Table 25 shows the New Jersey day-ahead, simple average LMP for the three planning periods: June 1, 2005 to May 31, 2006; June 1, 2006 to May 31, 2007; June 1, 2007 to December 31, 2007.

Table 25 New Jersey day-ahead, simple average LMP (Dollars per MWh):): June 1, 2005 to December 31, 2007

Planning Period	Day-Ahead LMP	Year-to-Year Change
Jun 1, 2005 - May 31, 2006	$68.88	NA
Jun 1, 2006 - May 31, 2007	$55.37	(19.6%)
Jun 1, 2007 - Dec 31, 2007	$66.70	20.4%

Zonal Day-Ahead, Average LMP

Table 26 shows zonal day-ahead, simple average LMP for the zones related to New Jersey for the three planning periods: June 1, 2005 to May 31, 2006; June 1, 2006 to May 31, 2007; June 1, 2007 to December 31, 2007.

Table 26 Zonal day-ahead, simple average LMP (Dollars per MWh): June 1, 2005 to December 31, 2007

Planning Period	AECO	JCPL	PSEG	RECO
Jun 1, 2005 - May 31, 2006	$70.07	$66.33	$69.88	$68.19
Jun 1, 2006 - May 31, 2007	$56.22	$53.82	$55.93	$55.54
Jun 1, 2007 - Dec 31, 2007	$66.21	$66.81	$66.76	$66.14

Day-Ahead, Load-Weighted, Average LMP

Day-ahead, load-weighted LMP reflects the average LMP paid for day-ahead demand MWh cleared during a year. Day-ahead, load-weighted LMP is the average day-ahead hourly LMPs, each weighted by the total cleared day-ahead hourly load, including day-ahead fixed load, price-sensitive load and decrement bids.

New Jersey Day-Ahead, Load-Weighted, Average LMP

Table 27 shows the New Jersey day-ahead, load-weighted, average LMP for the three planning periods: June 1, 2005 to May 31, 2006; June 1, 2006 to May 31, 2007; June 1, 2007 to December 31, 2007.

Table 27 New Jersey day-ahead, load-weighted, average LMP (Dollars per MWh): June 1, 2005 to December 31, 2007

Planning Period	Day-Ahead Load-Weighted LMP	Year-to-Year Change
Jun 1, 2005 - May 31, 2006	$75.11	NA
Jun 1, 2006 - May 31, 2007	$60.58	(19.4%)
Jun 1, 2007 - Dec 31, 2007	$72.31	19.4%

Zonal Day-Ahead, Load-Weighted LMP

Table 28 shows zonal day-ahead, load-weighted, average LMPs for zones related to New Jersey for the three planning periods: June 1, 2005 to May 31, 2006; June 1, 2006 to May 31, 2007; June 1, 2007 to December 31, 2007.

Table 28 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): June 1, 2005 to December 31, 2007

Planning Period	AECO	JCPL	PSEG	RECO
Jun 1, 2005 - May 31, 2006	$77.32	$73.23	$75.60	$74.99
Jun 1, 2006 - May 31, 2007	$63.16	$59.66	$60.43	$61.72
Jun 1, 2007 - Dec 31, 2007	$73.66	$73.22	$71.64	$72.15

Price Convergence

The PJM Day-Ahead Energy Market, introduced on June 1, 2000, includes the ability to make increment offers (INC) and decrement bids (DEC) at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. Since increment offers and decrement bids do not require physical generation or load, they are also referred to as virtual offers and bids. When the PJM Day-Ahead Energy Market was introduced, it was expected that competition, exercised substantially through the use of virtual offers and bids, would cause prices in the Day-Ahead and Real-Time Energy Markets to converge. Virtual offers and bids also provide participants the flexibility, for example, to cover one side of a bilateral transaction, hedge day-ahead generator offers or demand bids, and arbitrage day-ahead and real-time prices.

New Jersey Price Convergence

Although the introduction of PJM Day-Ahead Energy Market and virtual offers and bids was expected to cause prices in the Day-Ahead and Real-Time Energy Markets to converge, price convergence does not necessarily mean a zero or even a very small difference in prices between Day-Ahead and Real-Time Energy Markets. There may be factors, from operating reserve charges to risk that result in a competitive, market-based differential. In addition, convergence cannot occur within any individual day as there is at least a one-day lag after any change in system conditions. As a general matter, virtual offers and bids are based on expectations about both Day-Ahead and Real-Time Market conditions and reflects the uncertainty about conditions in both markets and the fact that these conditions change hourly and daily. Substantial, virtual trading activity does not guarantee that market power cannot be exercised in the Day-Ahead Energy Market.

Table 29 shows New Jersey average day-ahead and real-time LMP for the three planning periods: June 1, 2005 to May 31, 2006; June 1, 2006 to May 31, 2007; June 1, 2007 to December 31, 2007.

Table 29 Day-Ahead and Real-Time New Jersey LMP (Dollars per MWh): June 1, 2005 to December 31, 2007

Planning Period	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Jun 1, 2005 - May 31, 2006	$68.88	$69.73	$0.85	1.2%
Jun 1, 2006 - May 31, 2007	$55.37	$56.27	$0.90	1.6%
Jun 1, 2007 - Dec 31, 2007	$66.70	$69.22	$2.52	3.6%

Zonal Price Convergence

Table 30, Table 31 and Table 32 show zonal day-ahead and real-time average LMP for the zones related to New Jersey for the three planning periods: June 1, 2005 to May 31, 2006; June 1, 2006 to May 31, 2007; June 1, 2007 to December 31, 2007.

Table 30 Zonal Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): June 1, 2005 to May 31, 2006

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
AECO	$70.07	$70.25	$0.18	0.3%
JCPL	$66.33	$66.50	$0.17	0.3%
PSEG	$69.88	$71.21	$1.33	1.9%
RECO	$68.19	$69.51	$1.32	1.9%

Table 31 Zonal Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): June 1, 2006 to May 31, 2007

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
AECO	$56.22	$56.51	$0.29	0.5%
JCPL	$53.82	$54.24	$0.42	0.8%
PSEG	$55.93	$57.20	$1.27	2.2%
RECO	$55.54	$55.86	$0.32	0.6%

Table 32 Zonal Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): June 1, 2007 to December 31, 2007

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
AECO	$66.21	$69.18	$2.97	4.3%
JCPL	$66.81	$70.13	$3.32	4.7%
PSEG	$66.76	$68.68	$1.92	2.8%
RECO	$66.14	$67.97	$1.83	2.7%

Real-Time, Fuel-Cost-Adjusted, Load-Weighted LMP

Changes in LMP can result from changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of marginal cost depending on generating technology, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs.[18] To account for the changes in fuel cost between two given periods, for example between 2006 and 2007, the 2007 load-weighted LMP is adjusted to reflect the change in the daily price of fuels used by marginal units

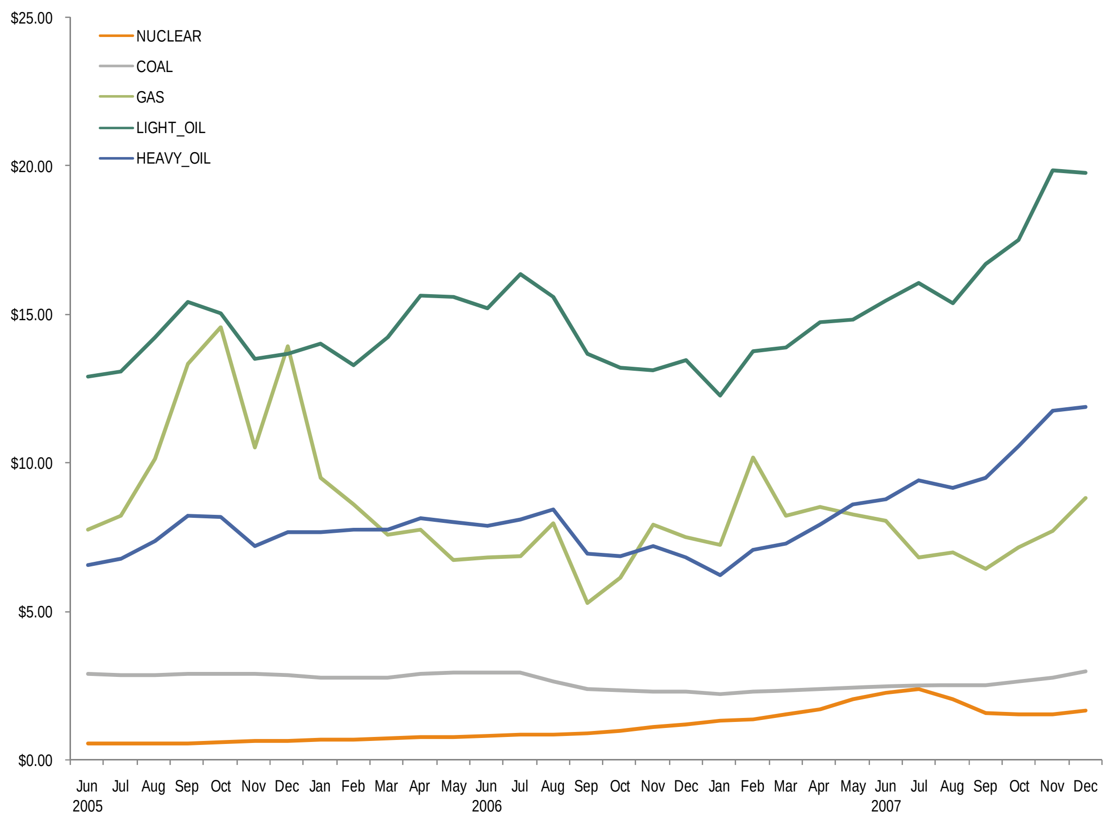
[18] See the *2007 State of the Market Report*, Volume II, Section 2,"Energy Market, Part 1," at Table 2-32, "Type of fuel used by marginal units: Calendar years 2005 to 2007."

and the change in the amount of load affected by marginal units, using sensitivity factors.[19]

The dominant fuels in PJM, coal declined in price in 2007 and natural gas increased in price in 2007. In 2007, coal prices were 5.9 percent lower than in 2006. Natural gas prices were 6.4 percent higher in 2007 than in 2006. No. 2 (light) oil prices were 9.7 percent higher and No. 6 (heavy) oil prices were 18.4 percent higher in 2007 than in 2006.

Since September 2007, the prices for light oil and heavy oil had been higher than those during the corresponding period in 2006. From September to December in 2007, coal prices were 17.1 percent higher, natural gas prices were 12.3 percent higher, No. 2 (light) oil prices were 38.2 percent and No. 6 (heavy) oil prices were 57.8 percent higher than the corresponding fuel prices during the same months in 2006. Figure 3 shows average, daily delivered coal, natural gas and oil prices for units within PJM.

Figure 3 Spot average fuel price comparison: June 2005 through December 2007



[19] For more information, see the *2007 State of the Market Report*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity Factors."

Figure 4 shows average, daily settled prices for NOx and SO_2 emission within PJM. In 2007, NOx prices were 56.5 percent lower than in 2006. SO_2 prices were 28.6 percent lower in 2007 than in 2006.[20]

Figure 4 Spot average emission price comparison: Calendar years 2006 to 2007

The fuel-adjusted load-weighted LMP was calculated for the AECO, JCPL, PSEG, and RECO zones, the state of New Jersey and the PJM system. Since unit sensitivity factors are not available prior to 2006, the fuel-adjusted load weighted LMP analysis is limited to three periods: January 1, 2006 to May 31, 2006; June 1, 2006 through May 31, 2007; and June 1, 2007 to December 31, 2007. The results are shown by aggregate and planning period in this section.

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[20] Natural gas prices are the daily cash price for Transco-Z6 (non-New York) adjusted for transportation to the burner tip. Light oil prices are the average of the daily price for No. 2 from the New York Harbor Spot Barge and from the Chicago pipeline and are adjusted for transportation. Heavy oil prices are a daily average of New York Harbor Spot Barge for 0.3 percent, 0.7 percent, 1.0 percent, 2.2 percent and 3.0 percent sulfur content. Coal prices are the 1.5 percent sulfur content per MBtu Central Appalachian coal, price-adjusted for transportation. All fuel prices are from Platts.

Fuel-cost adjusted, load-weighted LMP: Summary Statistics

Table 33 shows the New Jersey related zonal real-time, load-weighted, average LMP for the January 1, 2006 to May 31, 2006; June 1, 2006 to May 31, 2007; June 1, 2007 to December 31, 2007 periods for which the sensitivity based analysis was performed.

Table 33 Zonal real-time, load-weighted, average LMP (Dollars per MWh): January 1, 2006 to May 31, 2006; June 1, 2006 to May 31, 2007; June 1, 2007 to December 31, 2007

Planning Period	AECO	JCPL	PSEG	RECO
Jan 1, 2006 - May 31, 2006	$59.56	$56.48	$57.98	$58.59
Jun 1, 2006 - May 31, 2007	$63.34	$60.65	$62.57	$62.28
Jun 1, 2007 - Dec 31, 2007	$77.32	$77.69	$74.57	$75.19

Table 34, Table 35 and Table 36 provide the fuel cost adjusted, load weighted LMP for the AECO, JCPL, PSEG, and RECO zones, the state of New Jersey and the PJM system for each of the January 1, 2006 to May 31, 2006; June 1, 2006 through May 31, 2007; and June 1, 2007 to December 31, 2007 periods.

Table 34 shows that the AECO fuel-cost-adjusted, load-weighted, average LMP from January 2006 through May 2006 was 5.6 percent higher than the load-weighted LMP in 2005 during the same period. If fuel costs for the January through May 2006 period had been the same as for the January through May 2005 period, the AECO January through May 2006 period load-weighted LMP would have been lower, $56.95 per MWh instead of $59.56 per MWh.

Table 34 Period specific fuel-cost-adjusted, load-weighted LMP (Dollars per MWh) from January 2006 through May 2006

	2005 Load-Weighted LMP	2006 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
AECO	$53.96	$56.95	5.6%
JCPL	$54.40	$54.41	0.0%
PSEG	$54.72	$55.67	1.7%
RECO	$53.97	$56.01	3.8%
New Jersey	$54.51	$55.47	1.8%
PJM	$46.46	$50.71	9.2%

Table 35 shows that the AECO fuel-cost-adjusted, load-weighted, average LMP from June 2006 through May 2007 was 6.7 percent lower than the load-weighted LMP from the June 2005 to May 2006 period. If fuel costs for the June 2006 through May 2007 period had been the same as for the June 2005 to May 2006 period, the AECO June 2006 through May 2007 period load-weighted LMP would have been higher, $72.69 per MWh instead of $63.34 per MWh.

Table 35 Annual, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh) from June 2006 through May 2007

	2005/2006 Load-Weighted LMP	2006/2007 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
AECO	$77.91	$72.69	(6.7%)
JCPL	$74.21	$69.88	(5.8%)
PSEG	$77.39	$73.87	(4.6%)
RECO	$77.10	$74.06	(3.9%)
New Jersey	$76.55	$72.53	(5.2%)
PJM	$65.20	$65.03	(0.3%)

Table 36 shows that the AECO fuel-cost-adjusted, load-weighted, average LMP from June 2007 through December 2007 was 15.5 percent higher than the load-weighted LMP from the June 2006 to December 2006 period. If fuel costs for the June 2007 through December 2007 period had been the same as for the June 2006 through December 2006 period, the AECO June 2007 through December 2007 period load weighted LMP would have been lower, $74.02 per MWh instead of $77.32 per MWh.

Table 36 Annual, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh) from June 2007 through December 2007

	2006 Load-Weighted LMP	2007 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
AECO	$64.08	$74.02	15.5%
JCPL	$59.17	$73.10	23.5%
PSEG	$60.90	$69.67	14.4%
RECO	$61.06	$70.93	16.2%
New Jersey	$60.84	$71.28	17.2%
PJM	$53.84	$61.60	14.4%

Components of load-weighted, average LMP

Observed LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal units generally determine system LMPs based on their offers. Those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs and markup. As a result, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

Components of load-weighted, average LMP: Summary Statistics

Table 37, Table 38 and Table 39 provide the fuel, VOM, emissions and mark-up related components of the load weighted LMP for the AECO, JCPL, PSEG, and RECO zones, the state of New Jersey and the PJM system for each of the January 1, 2006 to May 31, 2006; June 1, 2006 through May 31, 2007; and June 1, 2007 to December 31, 2007 periods, respectively.

Table 37 Components of annual, load-weighted, average LMP (Dollars per MWh) from January 2006 through May 2006

Aggregate Name	Coal	Gas	Oil	Uranium	Wind	SO2	VOM	Markup	Constrained Off	NOX	NA	Annual Load-weighted LMP
AECO	$25.80	$15.92	$4.19	$0.00	$0.00	$7.48	$2.62	$0.15	$2.29	$0.77	$0.33	$59.56
JCPL	$26.40	$14.61	$1.74	$0.00	$0.01	$7.48	$2.52	$0.20	$2.40	$0.77	$0.36	$56.48
PSEG	$24.24	$17.38	$1.59	$0.00	$0.01	$6.76	$2.50	$0.86	$3.52	$0.72	$0.41	$57.98
RECO	$23.48	$18.11	$1.57	$0.00	$0.01	$6.43	$2.49	$1.15	$4.26	$0.71	$0.37	$58.59
New Jersey	$25.07	$16.37	$1.97	$0.00	$0.01	$7.06	$2.52	$0.59	$3.03	$0.74	$0.41	$57.77
PJM	$24.93	$12.53	$1.53	$0.00	$0.00	$7.07	$2.38	$0.53	$2.60	$0.73	$0.31	$52.61

Table 38 Components of annual, load-weighted, average LMP (Dollars per MWh) from June 2006 through May 2007

Aggregate Name	Coal	Gas	Oil	Uranium	Wind	SO2	VOM	Markup	Constrained Off	NOX	NA	Annual Load-weighted LMP
AECO	$20.45	$22.91	$6.49	$0.00	$0.01	$3.81	$3.59	$3.47	$0.25	$1.49	$0.86	$63.34
JCPL	$21.64	$19.29	$5.16	$0.00	$0.01	$4.13	$3.49	$3.78	$0.78	$1.53	$0.84	$60.65
PSEG	$19.20	$24.80	$4.43	$0.00	$0.01	$3.53	$3.38	$3.99	$0.91	$1.39	$0.92	$62.57
RECO	$19.06	$23.91	$4.04	$0.00	$0.01	$3.62	$3.31	$4.36	$1.32	$1.41	$1.24	$62.28
New Jersey	$20.08	$22.91	$4.92	$0.00	$0.01	$3.75	$3.44	$3.90	$0.75	$1.45	$0.90	$62.11
PJM	$20.58	$18.24	$3.89	$0.00	$0.01	$3.89	$3.28	$3.28	$0.36	$1.36	$0.54	$55.43

Table 39 Components of annual, load-weighted, average LMP (Dollars per MWh) from June 2007 through December 2007

Aggregate Name	Coal	Gas	Oil	Uranium	Wind	SO2	VOM	Markup	Constrained Off	NOX	NA	Annual Load-weighted LMP
AECO	$24.44	$22.32	$5.86	$0.00	$0.01	$5.12	$5.11	$7.54	$4.66	$1.15	$1.10	$77.32
JCPL	$23.99	$22.75	$5.39	$0.00	$0.01	$5.25	$5.56	$7.90	$4.62	$1.18	$1.03	$77.69
PSEG	$24.03	$20.84	$4.60	$0.00	$0.01	$5.25	$5.35	$8.01	$4.42	$1.16	$0.90	$74.57
RECO	$23.72	$21.43	$4.20	$0.00	$0.01	$5.32	$5.35	$8.15	$4.82	$1.19	$1.01	$75.19
New Jersey	$24.07	$21.61	$4.99	$0.00	$0.01	$5.23	$5.38	$7.95	$4.48	$1.16	$0.97	$75.86
PJM	$22.41	$15.91	$3.75	$0.00	$0.01	$5.02	$4.35	$6.55	$4.72	$1.00	$0.65	$64.38

Marginal Losses

Marginal losses are the incremental change in system real power losses caused by changes in the system load and generation patterns.[21] Before June 1, 2007, the PJM economic dispatch and LMP models did not include marginal losses. The losses were treated as a static component of load, and the physical nature and location of power system losses were ignored. The PJM Tariff required implementation of marginal loss modeling when required technical systems became available. On June 1, 2007, PJM began including marginal losses in economic dispatch and LMP models.[22] The primary benefit of a marginal loss mechanism is that it more accurately models the physical reality of power system losses. More accurate models permit increased efficiency and optimize asset utilization. One characteristic of marginal loss modeling is that it creates a separate marginal loss price for every location on the power grid.

Marginal Loss Accounting

With the implementation of marginal loss pricing, PJM calculates transmission loss charges for each PJM member. The loss charge is based on the applicable day-ahead and real-time loss component of LMP (loss LMP). Each PJM member is charged for the cost of losses on the transmission system, based on the difference between the loss LMP at

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21 For additional information, see the *2007 State of the Market Report*, Volume II, Appendix J, "Marginal Losses."

22 For additional information, see PJM. "Open Access Transmission Tariff" (December 10, 2007), Section 3.4, Original Sheet No. 388G.

the location where the PJM member injects energy and the loss LMP where the PJM member withdraws energy. For purposes of this report, only the real-time load loss costs are calculated. The load loss costs are calculated by multiplying the total load for a zone by the applicable loss component of LMP. Table 40 shows the monthly total load loss costs for New Jersey related zones for the 2007/2008 period.

Table 40 Total New Jersey load loss costs by month (Dollars (Millions): June 1, 2007 to December 31, 2007

Marginal Loss Costs by Control Zone (Millions)								
Control Zone	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
AECO	$3.9	$5.2	$5.7	$3.8	$3.0	$2.5	$3.5	$27.6
JCPL	$6.7	$8.6	$7.4	$7.0	$6.1	$5.9	$8.9	$50.7
PSEG	$13.5	$16.4	$14.4	$14.1	$13.3	$12.0	$16.6	$100.4
RECO	$0.4	$0.5	$0.5	$0.5	$0.4	$0.4	$0.5	$3.2
Total	$24.6	$30.7	$28.0	$25.4	$22.9	$20.8	$29.5	$181.9

Demand-Side Response (DSR)

The PJM Economic Load-Response Program is a PJM-managed accounting mechanism that provides for payment of the savings that result from load reductions to the load-reducing customer. Such a mechanism is required because of the complex interaction between the wholesale market and the retail incentive and regulatory structures faced by both load-serving entities (LSEs) and customers. The broader goal of the Economic Program is a transition to a structure where customers do not require mandated payments, but where customers see and react to market prices or enter into contracts with intermediaries to provide that service. Even as currently structured, however, the Economic Program represents a minimal and relatively efficient intervention into the market. Table 41, Table 42 and Table 43 show the cost of the Economic DSR program, and the cost per MWh of load by New Jersey zone for each of the January 1, 2006 to May 31, 2006; June 1, 2006 through May 31, 2007; and June 1, 2007 to December 31, 2007 periods. The costs of the DSR program on a per MWh basis are included in the Ancillary Services section under "other costs."

Table 41: Cost of the Economic DSR program by New Jersey aggregate: June 1, 2005 to May 31, 2006[23]

	Charges		
Zone	Customer LSE	Zonal LSEs	$/MWh of load
AECO	$193,300.42	$109,453.68	$0.03
JCPL	$5,933.85	$3,243.08	$0.00
PSEG	$151,035.08	$273,915.04	$0.01
RECO	$172.64	$153.41	$0.00
New Jersey	$350,441.99	$386,765.21	$0.01

Table 42: Cost of the Economic DSR program by New Jersey aggregate: June 1, 2006 to May 31, 2007

	Charges		
Zone	Customer LSE	Zonal LSEs	$/MWh of load
AECO	$28,379.01	$53,439.32	$0.01
JCPL	-$297.50	$85,791.75	$0.00
PSEG	$152,802.38	$649,358.18	$0.02
RECO	$0.00	$0.00	$0.00
New Jersey	$180,883.89	$788,589.25	$0.01

Table 43: Cost of the Economic DSR program by New Jersey aggregate: June 1, 2007 to December 31, 2007

	Charges		
Zone	Customer LSE	Zonal LSEs	$/MWh of load
AECO	$45,745.58	$14,029.75	$0.01
JCPL	$14,583.13	$1,391,419.57	$0.09
PSEG	$228,085.93	$196,202.81	$0.01
RECO	$2,275.78	$440.33	$0.00
New Jersey	$290,690.42	$1,602,092.46	$0.04

Balancing Operating Reserve Rate

Day-ahead and real-time operating reserve credits are paid to generation owners under specified conditions in order to ensure that units are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or revenue requirement make whole, these payments are intended to be one of the incentives to generation owners to offer

[23] Table 41 through Table 43 show data by PJM dispatched zones. For example, New Jersey state might include customers that are in the zones it does not exclude customers that are in the zone but not in the state.

their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges.

If a unit is selected to operate in the PJM Day-Ahead Energy Market but the market revenues for the entire day resulting from that operation are insufficient to cover all offer components, including startup and no-load, then day-ahead operating reserve credits ensure that all offer components are covered.[24] If a generator, scheduled to operate in the Real-Time Energy Market, operates as directed by PJM dispatchers but the market revenues for the entire day resulting from that operation are insufficient to cover all offer components, then balancing operating reserve credits ensure that all offer components are covered.

The level of operating reserve credits paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters as well as the decisions of PJM operators. Operating reserve credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, startup and no-load offers.

From the perspective of those participants paying operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

The balancing operating reserve rate equals the total daily amount of balancing operating reserve credits divided by total daily deviations. It is calculated daily. Table 44 shows the total and average per MWh cost to load of Balancing Operating Reserve charges for each of the January 1, 2006 to May 31, 2006; June 1, 2006 through May 31, 2007; and June 1, 2007 to December 31, 2007 periods. Figure 5 shows the monthly average balancing operating reserve rates for PJM for each of the January 1, 2006 to May 31, 2006; June 1, 2006 through May 31, 2007; and June 1, 2007 to December 31, 2007 periods.

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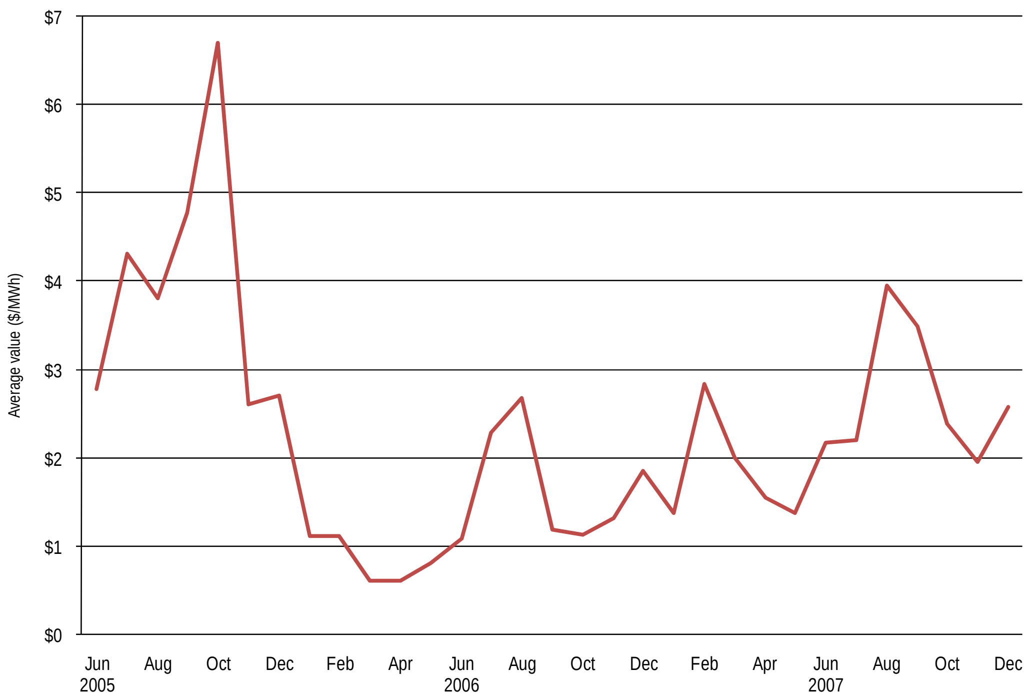
[24] Operating reserve credits are also provided for pool-scheduled energy transactions, for generating units operating as condensers not as synchronized reserve, for the cancellation of pool-scheduled resources, for units backed down for reliability reasons, for units performing black start tests and for units providing quick start reserve.

Table 44 Total and average $/MWh of load, load balancing charges by period

Period	Total Load Balancing Charges	$/MWh
June 1, 2005 to May 31, 2006	$310,320,132.48	$0.44
June 1, 2006 to May 31, 2007	$169,245,028.45	$0.24
June 1, 2007 to December 31, 2007	$142,673,923.60	$0.34

Figure 5 Monthly average balancing operating reserve rate for PJM: June 1, 2005 through December 2007



Capacity Markets

Effective June 1, 2007, the PJM Capacity Credit Market (CCM), which had been the market design since 1999, was replaced with the Reliability Pricing Model (RPM) Capacity Market construct. The CCM consisted of the Daily, Interval, Monthly and Multimonthly CCM.[25] The CCM was intended to provide a transparent, market-based mechanism for retail LSEs to acquire the capacity resources needed to meet their capacity obligations and to sell capacity resources when no longer needed to serve load. The Daily CCM permitted LSEs to match capacity resources with short-term shifts in retail load while the Interval, Monthly and Multimonthly CCMs provided mechanisms to match longer-term obligations to serve load with capacity resources.

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

Under RPM, capacity obligations are annual. Under CCM, capacity obligations were daily. Under RPM, auctions are held for delivery years that are three years in the future. Under CCM daily, monthly and multimonthly auctions were held. Under RPM, prices are locational and may vary depending on transmission constraints.[26] Under CCM, prices were the same, regardless of location. Under RPM, sell offers are unit-specific. Under CCM, offers were non-unit-specific capacity credits. Under RPM, existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for the fixed resource requirement (FRR) option. Under CCM, there was no must-offer rule after June 2000. Under RPM, participation by LSEs is mandatory, except for the FRR option. Under CCM, there was no mandatory participation in the CCM auctions. Under RPM, there is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity

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

26 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.

offers, determines market prices. Under CCM the demand was defined by participant buy bids. Under RPM there are performance incentives for generation. Under CCM the only performance incentive was the direct relationship between historical EFORd and the amount of capacity that could be sold. Under RPM there are explicit market power mitigation rules that define structural market power, that define offer caps based on the marginal cost of capacity and that do not limit prices offered by new entrants. Under CCM, there were no explicit market power mitigation rules. Under RPM, demand-side resources may be offered directly into the auctions and receive the clearing price. Under CCM, demand-side resources could not be offered directly into the market.

From June 2005 through May 2006, the volume-weighted, average price for the entire CCM was $4.53 per MW-day (Table 45). From June 2006 through May 2007, the volume-weighted, average price for the entire CCM was $5.22 per MW-day (Table 46). These prices applied to all PJM load including load in each New Jersey zone.

Table 45 PJM capacity prices: June 2005 through May 2006

	CCM Combined Markets Weighted-Average Price ($ per MW-day)
Jun-05	$7.76
Jul-05	$7.13
Aug-05	$5.69
Sep-05	$5.54
Oct-05	$4.14
Nov-05	$3.80
Dec-05	$3.65
Jan-06	$7.89
Feb-06	$2.65
Mar-06	$2.60
Apr-06	$2.49
May-06	$2.19
Average	$4.53

Table 46 PJM capacity prices: June 2006 through May 2007

	CCM Combined Markets Weighted-Average Price ($ per MW-day)
Jun-06	$10.28
Jul-06	$8.57
Aug-06	$7.09
Sep-06	$6.98
Oct-06	$5.30
Nov-06	$5.08
Dec-06	$4.55
Jan-07	$3.83
Feb-07	$3.17
Mar-07	$3.02
Apr-07	$3.06
May-07	$3.03
Average	$5.22

Under RPM, New Jersey is included in the EMAAC locational deliverability area (LDA). The net load price that EMAAC LSEs pay from June 2007 through May 2008 is $177.00 per MW-day (Table 47). This value is the final zonal capacity price ($197.16 per MW-day) less the final CTR credit rate ($20.16 per MW-day). The CTR MW value allocated to load in an LDA is the LDA UCAP obligation less the cleared generation internal to the LDA less the ILR forecast for the LDA. This MW value is multiplied by the locational price adder for the LDA to arrive at the economic value of the CTRs allocated to the load in the LDA. This value is then divided by the LDA UCAP obligation to arrive at the final CTR credit rate for the LDA. The final CTR credit rate is an allocation of the economic value of transmission import capability that exists in constrained LDAs and serves to offset a portion of the locational price adder charged to load in constrained LDAs.

Table 47 EMAAC RPM capacity prices: June 2007 through May 2008

	EMAAC ($ per MW-day)
Resource clearing price	$197.67
Final zonal capacity price	$197.16
Final zonal CTR credit rate	$20.16
Net load price	$177.00

Table 48 shows the zone and aggregate specific average per MWh cost of capacity for each of the January 1, 2006 to May 31, 2006; June 1, 2006 through May 31, 2007; and June 1, 2007 to December 31, 2007 periods.

Table 48 Capacity cost per MWh by zone and aggregate by period

Period	AECO	JCPL	PSEG	RECO	NJ	PJM
June 1, 2005 - May 31, 2006	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
June 1, 2006 - May 31, 2007	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
June 1, 2007 - December 31, 2007	$15.20	$16.40	$14.79	$16.79	$15.36	$3.67

Ancillary Services

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order 888: 1) scheduling, system control and dispatch; 2) reactive supply and voltage control from generation service; 3) regulation and frequency response service; 4) energy imbalance service; 5) operating reserve – synchronized reserve service; and 6) operating reserve – supplemental reserve service.[27] Of these, PJM currently provides regulation, energy imbalance and synchronized reserve services through market-based mechanisms. PJM provides energy imbalance service through the Real-Time Energy Market. PJM provides the remaining ancillary services on a cost basis. Table 49 shows total ancillary service charges for PJM by ancillary service for each of the January 1, 2006 to May 31, 2006; June 1, 2006 through May 31, 2007; and June 1, 2007 to December 31, 2007 periods. Table 50 shows the total ancillary service related charges an and the per MWh charge for ancillary services for each of the January 1, 2006 to May 31, 2006; June 1, 2006 through May 31, 2007; and June 1, 2007 to December 31, 2007 periods.

Table 49 Total Ancillary Service Charges by Charge Type and Period

Charge Type	June 1, 2005 to May 31, 2006	June 1, 2006 to May 31, 2007	June 1, 2007 to December 31, 2007
Other Charges	$467,959,429.28	$508,629,219.77	$303,263,140.76
Regulation	$543,286,970.12	$408,909,565.48	$279,520,134.80
Synchronized Reserve	$93,168,175.67	$80,275,057.36	$41,362,527.32

27 75 FERC ¶ 61,080 (1996).

Table 50 Total Ancillary Service Charges and Cost of Ancillary Services per MWh, by Period.

Period	Ancillary Services Charges	$/MWh cost of Ancillary Services
June 1, 2005 to May 31, 2006	$1,104,414,575.07	$1.55
June 1, 2006 to May 31, 2007	$997,813,842.61	$1.40
June 1, 2007 to December 31, 2007	$624,145,802.88	$1.47

Regulation matches generation with very short-term changes in load by moving the output of selected generators up and down via an automatic control signal.[28] Regulation is provided, independent of economic signal, by generators with a short-term response capability (i.e., less than five minutes) or by demand-side response (DSR). Longer-term deviations between system load and generation are met via primary and secondary reserve and generation responses to economic signals. Synchronized reserve is a form of primary reserve. To provide synchronized reserve a generator must be synchronized to the system and capable of providing output within 10 minutes. Synchronized reserve can also be provided by DSR. The term, Synchronized Reserve Market, refers only to supply of and demand for Tier 2 synchronized reserve.

Both the Regulation and Synchronized Reserve Markets are cleared on a real-time basis. A unit can be selected for either regulation or synchronized reserve, but not for both. The Regulation and the Synchronized Reserve Markets are cleared interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products, subject to reactive limits, resource constraints, unscheduled power flows, interarea transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

PJM does not provide a market for reactive power, but does ensure its adequacy through member requirements and scheduling. Generation owners are paid according to the FERC-approved, reactive revenue requirements. Charges are allocated to network customers based on their percentage of load, as well as to point-to-point customers based on their monthly peak usage.

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

The MMU analyzed measures of market structure, conduct and performance of the PJM Regulation Market and of its two Synchronized Reserve Markets for 2007, comparing market results to 2006 and to certain other prior years.[29]

The ancillary services markets have had several unique geographies, and structures during the timeframe of this study.

Regulation Market:

Period 1a: June 1, 2005 – July 31, 2005 (PJM Mid-Atlantic market)

Period 1b: August 1, 2005 – May 31, 2006 (Combined Regulation Market)

Period 2: June 1, 2006 – May 31, 2007 (Combined Regulation Market)

Period 3: June 1, 2007 – December 31, 2007 (Combined Regulation Market)

Spinning Market:

Period 1: June 1, 2005 – May 31, 2006 (PJM Mid-Atlantic market)

Period 2a: June 1, 2006 – January 31, 2007 (PJM Mid-Atlantic market)

Period 2b: February 1, 2007 – May 31, 2007 (Combined Spinning Market)

Period 3: June 1, 2007 – December 31, 2007 (Combined Spinning Market)

Regulation Market

PJM consolidated its Regulation Markets into a single Combined Regulation Market, effective August 1, 2005. The MMU concludes from the analysis of the 2006 data that the PJM Regulation Market in 2006 was characterized by structural market power in 26

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

percent of the hours.[30] This conclusion is based on the results of the three pivotal supplier test. The MMU also concludes that PJM's consolidation of its Regulation Markets resulted in improved performance and in increased competition compared to the PJM Mid-Atlantic Regulation Market or the Western Region Regulation Market on a stand-alone basis.[31] The MMU also concludes that the performance of the Regulation Market was more competitive in calendar year 2006 than during the first 12 months of the Regulation Market, August 1, 2005, through July 31, 2006.

The market structure of the 2007 PJM Regulation Market remained similar to the market structure of the 2006 Regulation Market. DSR participation was introduced in 2006, but demand-side resources did not qualify and make offers in the Regulation Market in either 2006 or 2007. These conclusions are based on improved HHI results and fewer hours during which there were three pivotal suppliers. The combined market results include the effects of the current mitigation mechanism which offer caps the two dominant suppliers in every hour. The MMU continues to conclude that it would be preferable to retain the existing, experimental single PJM Regulation Market as the long-term market if appropriate mitigation can be implemented that addresses only the hours in which structural market power exists and which therefore provides an incentive for the continued development of competition.

Total capability is a theoretical measure of maximum regulation capability offered. The level of regulation resources offered on a daily level and the level of regulation resources both offered and eligible to participate on an hourly level in the market were lower than the total regulation capability. Although regulation is offered daily, eligible regulation changes hourly. Typically less regulation is eligible to be assigned during off-peak hours because fewer steam units are running during those hours. Table 51 shows capability, daily offer, average hourly eligible MW, offered MW as a percentage of regulation capacity and eligible MW for all hours by the defined market periods.[32]

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

31 *2005 State of the Market Report* (March 8, 2006), pp. 260-263.

32 Period 1a: June 1, 2005 – July 31, 2005 (PJM Mid-Atlantic market), Period 1b: August 1, 2005 – May 31, 2005 (Combined Regulation Market), Period 2: June 1, 2006 – May 31, 2007 (Combined Regulation Market), Period 3: June 1, 2007 – December 31, 2007 (Combined Regulation Market).

Table 51 PJM Regulation capability, daily offer and hourly eligible

Period	Capacity	Daily Offered MW	Offer MW as Percentage of Capacity	Daily Eligible MW	Eligible MW as percentage of Capacity
Period 1a	2692	1265	47	878	33
Period 1b	5773	3331	58	2062	36
Period 2	7095	3916	55	2332	33
Period 3	7165	4126	58	1923	27

Although most hours had a market participant with a market share greater than 20 percent, the highest annual average hourly market share by a company was 15.6 percent. The top six period specific average hourly market shares for cleared regulation are listed in Table 52.

Table 52 Highest annual average Regulation Market shares

Rank Order	Period 3	Period 2	Period 1b
1	15.6%	14.4%	12.6%
2	12.5%	12.3%	10.6%
3	10.8%	12.2%	10.6%
4	10.7%	10.3%	9.8%
5	7.6%	7.9%	9.8%
6	7.1%	7.1%	9.5%

When all eligible regulating units whose price is less than, or equal to, the market-clearing price times 1.5 are included in the definition of the relevant market, 57 percent of hours failed the one pivotal supplier test during period 3, 50 percent of the hours failed the three pivotal supplier test during period 2 and 57 percent of the hours failed the three pivotal supplier test during period 1b (See Table 53.)

The MMU concludes from these results that the PJM Regulation Market in all three periods was characterized by structural market power. This conclusion is based on the pivotal supplier results and, in particular, on the results of the three pivotal supplier test with a market definition that includes all offers with a price less than, or equal to, 1.50 times the market-clearing price.[33]

[33] The structural and behavioral issues in the Regulation Market were addressed by the implementation of the three pivotal supplier test effective January 1, 2008.

Table 53 Regulation Market pivotal suppliers

Period	Hours with Three Pivotal Suppliers (Percent)
Period 3	77%
Period 2	50%
Period 1b	57%

Table 54 shows the PJM Regulation Market daily MW weighted average market-clearing price, MW weighted lost opportunity cost and MW weighted offer price by defined period.[34]

Table 54 PJM Regulation Market daily average market-clearing price, lost opportunity cost and offer price (Dollars per MW)

Period	Load weighted average offer price	Load weighted average lost opportunity cost	Average Regulation Market clearing price
Period 3	$12.99	$22.63	$37.30
Period 2	$11.63	$26.64	$34.99
Period 1b	$9.30	$40.45	$45.65
Period 1a	$13.37	$42.32	$54.11

Figure 6, Figure 7 and Figure 8 show the monthly average daily regulation market clearing prices, lost opportunity costs daily operating reserve rates for PJM for each of the January 1, 2006 to May 31, 2006; June 1, 2006 through May 31, 2007; and June 1, 2007 to December 31, 2007 periods, respectively.

[34] Period 1a: June 1, 2005 – July 31, 2005 (PJM Mid-Atlantic market), Period 1b: August 1, 2005 – May 31, 2005 (Combined Regulation Market), Period 2: June 1, 2006 – May 31, 2007 (Combined Regulation Market), Period 3: June 1, 2007 – December 31, 2007 (Combined Regulation Market).

Figure 6 PJM Regulation Market daily average market-clearing price, lost opportunity cost and offer price (Dollars per MW) for January 1, 2006 to May 31, 2006

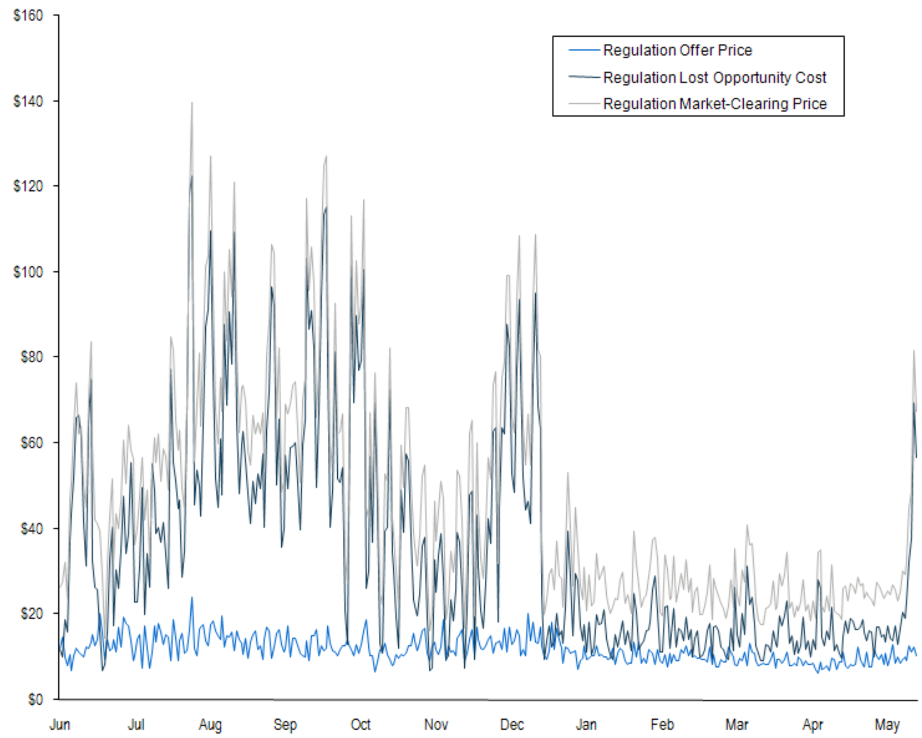


Figure 7 PJM Regulation Market daily average market-clearing price, lost opportunity cost and offer price (Dollars per MW) for June 1, 2006 through May 31, 2007

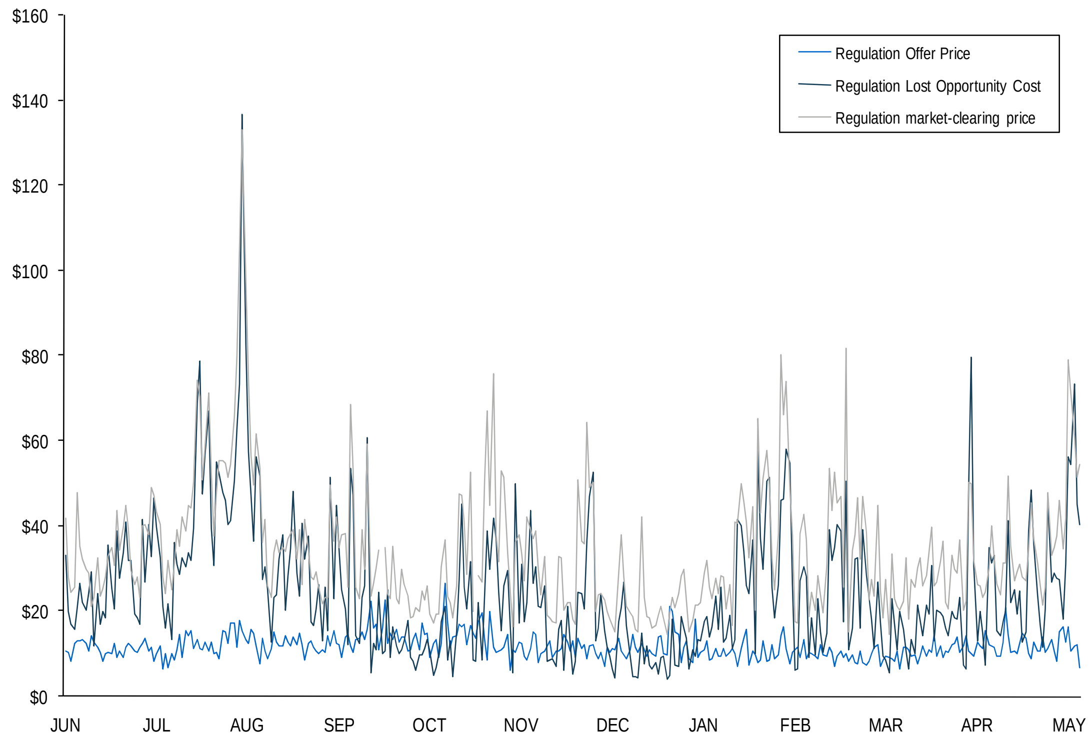
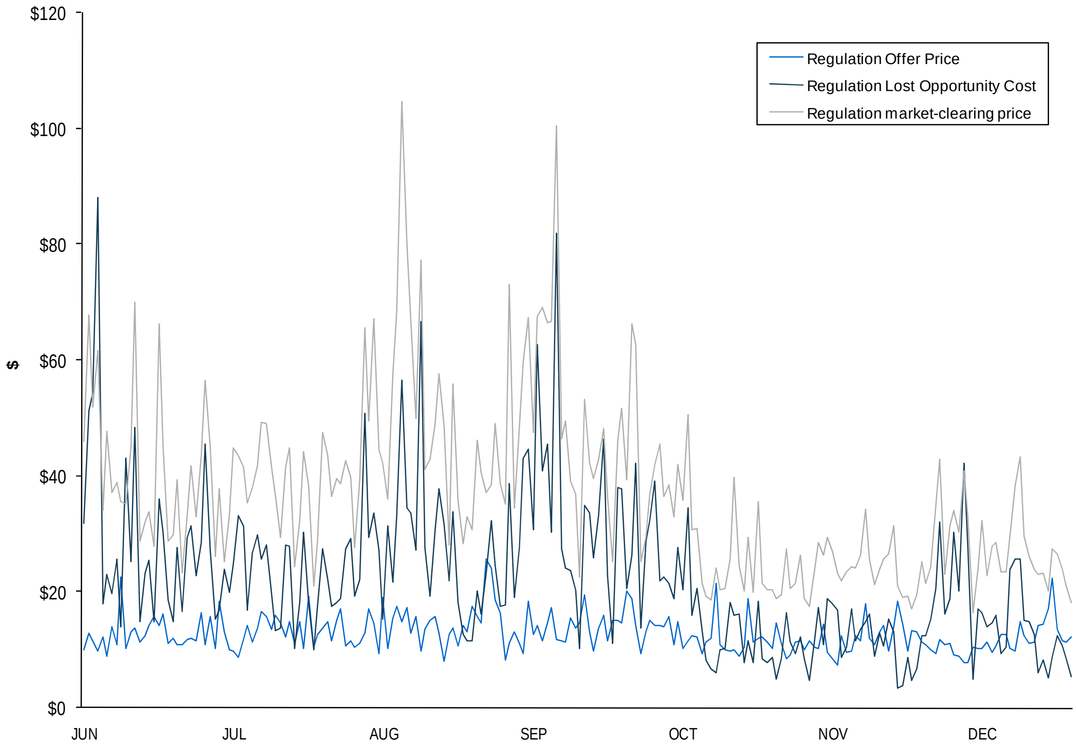


Figure 8 PJM Regulation Market daily average market-clearing price, lost opportunity cost and offer price (Dollars per MW) for June 1, 2007 to December 31, 2007



Synchronized Reserve Market

The structure of each Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. (The term, Synchronized Reserve Market, refers only to Tier 2 synchronized reserve.) As a result, these markets are operated as markets with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. Prices for synchronized reserve in the RFC Synchronized Reserve Zone and in the Southern Synchronized Reserve Zone are market-clearing prices determined by the supply curve and the administratively defined demand. The cost-based synchronized reserve offers are defined to be the unit-specific incremental cost of providing synchronized reserve plus a margin of $7.50 per MWh plus lost opportunity cost calculated by PJM.

There was a significant change in the operation of the Synchronized Reserve Market in the last quarter of 2007 as PJM relied less on the market and more on out-of-market purchases of spinning reserve for local needs. Beginning in October and increasing substantially in November and December, there was an increase in the amount of combustion-turbine-based, synchronized condenser MW added by PJM market operations to the Synchronized Reserve Market after market clearing. MW added after the market cleared accounted for more than 50 percent of total synchronized reserve MW purchased in December.

The increase in out-of-market purchases indicates that the Synchronized Reserve Market is not functioning to coordinate supply and demand. It is not clear why the additional synchronized reserve requirements cannot be procured via the market.

The Tier 2 Synchronized Reserve Market is the only Synchronized Reserve Market cleared by PJM. Although the RFC Tier 2 Synchronized Reserve Market was less concentrated in 2007 than the four PJM Tier 2 Synchronized Reserve Markets had been in 2006, the 2007 RFC Synchronized Reserve Market remains highly concentrated and dominated by a relatively small number of companies.

The pivotal supplier metric provides an analytical approach to the issue of market excess supply and structural market power.[35] Table 55 shows the percentage of hours that one or more participants failed the three pivotal supplier test in the spinning market, by period.

Table 55 Spinning Market pivotal suppliers[36]

Period	Hours with Three Pivotal Suppliers (Percent)
Period 3	44%
Period 2b	71%
Period 2a	35%
Period 1	68%

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

36 Period 1a: June 1, 2005 – July 31, 2005 (PJM Mid-Atlantic market), Period 1b: August 1, 2005 – May 31, 2005 (Combined Regulation Market), Period 2: June 1, 2006 – May 31, 2007 (Combined Regulation Market), Period 3: June 1, 2007 – December 31, 2007 (Combined Regulation Market).

Market Performance

Price

Table 56 shows the load-weighted, average Tier 2 price (SRMCP • MW cleared) and the average Tier 2 cost per MW associated with meeting PJM demand for synchronized reserve (total credits paid • MW purchased). The price of Tier 2 synchronized reserve is called the synchronized reserve market-clearing price (SRMCP). Resources which provide synchronized reserve are paid the higher of the SRMCP or their offer plus their unit-specific LOC. The offer plus the unit-specific LOC may exceed the SRMCP for a number of reasons. If real-time LMP is greater than the LMP forecast prior to the operating hour and included in the SRMCP, unit-specific LOC will be higher than forecast. Such higher LMPs can be local because of congestion or more general if system conditions change. The additional costs of noneconomic dispatch are added to the total cost of synchronized reserve. When some units are paid the value of their offer plus their unit-specific LOC, the result is that PJM's synchronized reserve cost per MWh is higher than the SRMCP.

Table 56 Spinning Price vs. Cost (Dollars per MW)

Period	Load weighted Spinning Reserve Market Clearing Price	Spinning Cost
Period 1	$14.55	$19.40
Period 2a	$14.93	$17.08
Period 2b	$18.66	$23.34
Period 3	$11.26	$16.27

Congestion

Congestion occurs when available, least-cost energy cannot be delivered to all loads for a period because transmission facilities are not adequate to deliver that energy to some loads. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[37] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Locational marginal prices (LMPs) reflect the price of the lowest-cost resources available to meet loads, taking into account actual delivery constraints imposed by the transmission system. Thus LMP is an efficient way to price energy when transmission constraints exist. Congestion reflects this efficient pricing.

Congestion reflects the underlying features of the power system including the nature and capability of transmission facilities and the cost and geographical distribution of generation facilities. Congestion is neither good nor bad but is a direct measure of the extent to which there are differences in the cost of generation that cannot be equalized because of transmission constraints. A complete set of markets would permit direct competition between investments in transmission and generation. The transmission system provides a physical hedge against congestion. The transmission system is paid for by firm load and, as a result, firm load receives the corollary financial hedge in the form of Auction Revenue Rights (ARRs) and/or Financial Transmission Rights (FTRs). While the transmission system and, therefore, ARRs/FTRs are not guaranteed to be a complete hedge against congestion, ARRs/FTRs do provide a substantial offset to the cost of congestion to firm load.[38]

The MMU analyzed congestion and its influence on transmission zones within the state of New Jersey from June 1, 2005 through December 31, 2007.[39]

Load Congestion Costs

Congestion can exist in PJM's Day-Ahead and Real-Time Energy Market. To the extent that a participant bids all load in the Day-Ahead Market, load is not exposed to real-time

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37 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean that the next unit in merit order cannot be used and that a higher cost unit must be used in its place.

38 See the *2007 State of the Market Report*, Volume II, Section 8, "Financial Transmission and Auction Revenue Rights," at "ARR and FTR Revenue and Congestion."

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

congestion costs and pays the congestion incurred in the Day-Ahead Market. New Jersey's BGS auctions award real time load obligations, so this analysis measures only the real-time exposure to real time congestion for load served by auction winners in New Jersey.[40]

Real-time load congestion cost at a bus is equal to the product of real-time hourly bus demand MWh and the real-time hourly bus congestion component of LMP (CLMP). The total real-time load congestion cost equals the summation of all real-time load congestion costs at each bus.

The congestion costs associated with specific constraints are the sum of the total real-time load congestion costs associated with those constraints. The congestion costs in each zone are the sum of the congestion costs associated with each constraint that affects prices in the zone. The network nature of the transmission system means that congestion costs in a zone are frequently the result of constrained facilities located outside that zone.

Congestion costs can be both positive and negative. When a constraint binds, the price effects of that constraint vary. The system marginal price (SMP) is uniform for all areas, while the congestion components of LMP will either be positive or negative in a specific area, meaning that actual LMPs are above or below the SMP.[41] Usually a smaller area affected by a constraint will have increased prices and the larger unconstrained system will have lower prices. If an area is located upstream from the constrained element, the area will experience negative congestion costs (lower prices) from that constrained element. Conversely, positive congestion costs occur when an area is located downstream from a constrained element.

Zonal Congestion

Summary

Real-time load congestion costs for specific zones within the state of New Jersey are presented in Table 57 by planning period. The PSEG Control Zone, with $366.7 million, incurred the most congestion charges in the June 2007 to December 2007 period. The

40 The terms *congestion charges* and *congestion costs* are both used to refer to the costs associated with congestion. The term, congestion charges, is used in documents by PJM's Market Settlement Operations.

41 The SMP is the price of the distributed load reference bus. The price at the reference bus is equivalent to the five minute real-time load weighted PJM LMP.

leading contributors to congestion in the PSEG Control Zone in the June 2007 to December 2007 period were the Branchburg – Readington line and Kammer transformer constraints. These two facilities contributed $63.7 and $35.5 million in positive congestion costs, and together constituted 35 percent of all congestion charges in the PSEG Control Zone. The JCPL Control Zone, with $255.1 million, incurred the second highest amount of congestion charges in the 2007 to 2008 planning period. The leading contributors to congestion in the JCPL Control Zone in the June 2007 to December 2007 period were the Atlantic – Larrabee line and Branchburg – Readington line constraints. These two facilities contributed $58.8 and $55.6 million in positive congestion costs, and together constituted 50 percent of all congestion charges in the JCPL Control Zone.

Table 57 Load congestion cost summary (By control zone): Planning periods 2005 to 2006, 2006 to 2007, and 2007 through December, 2007

	Real-Time Load Congestion Costs (Millions)			
Control Zone	2005/2006	2006/2007	2007/2008	Total
AECO	$171.6	$116.7	$90.1	$378.4
JCPL	$253.0	$167.4	$255.1	$675.5
PSEG	$695.6	$456.4	$366.7	$1,518.7
RECO	$19.5	$12.8	$11.2	$43.5
Total	$1,139.7	$753.3	$723.1	$2,616.1

Details of Zonal Congestion

Constraints were examined by zone within the state of New Jersey. Zones correspond to regulated utility franchise areas. Regions generally comprise two or more zones. PJM is comprised of three regions: the PJM Mid-Atlantic Region with 11 control zones (the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, PEPCO, PPL, PSEG and RECO control zones); the PJM Western Region with five control zones (the AP, ComEd, AEP, DLCO and DAY control zones); and the PJM Southern Region with one control zone (the Dominion Control Zone).

Table 60 through Table 69 present the top constraints affecting zonal congestion costs by control zone within the state of New Jersey, and demonstrate the influence of individual constraints on zonal congestion costs by planning period. Total congestion costs associated with a given constraint may be positive or negative in value. The top constraints affecting zonal congestion costs are presented by constraint, in descending order of the absolute value of total congestion costs. Real-time congestion-event hours are presented for each of the highlighted constraints. Constraints can have wide-ranging effects, influencing prices across multiple zones.

New Jersey Zonal Congestion-Event Summaries

AECO Control Zone

Table 58 through Table 60 show the constraints with the largest impacts on total congestion cost in the AECO Control Zone by planning period. In the 2005 to 2006 planning period, the Laurel – Woodstown line, and the Bedington – Black Oak interface constraints were the largest contributors to positive congestion while the Cedar Grove — Roseland and the Branchburg – Readington lines contributed most to negative congestion. In the 2006 to 2007 planning period, the Laurel – Woodstown and Bedington – Black Oak lines were the largest contributors to positive congestion while the Branchburg— Readington line and the Cedar Grove – Roseland line contributed the most to negative congestion. In the 2007 to 2008 planning period, the Beckett – Paulsboro and Quinton – Roadstown lines were the largest contributors to positive congestion costs while Atlantic – Larabee and Branchburg – Readington lines were the largest contributors to negative congestion costs.

Table 58 AECO Control Zone top congestion cost impacts (By facility): Planning period 2005 to 2006

Real Time Congestion Costs (Millions)				
Constraint	Type	Location	Load Congestion Costs	Event Hours
Laurel - Woodstown	Line	AECO	$31.6	1,194
Bedington - Black Oak	Interface	500	$29.7	1,966
Kammer	Transformer	500	$20.8	1,805
Doubs - Mount Storm	Line	500	$19.3	580
5004/5005 Interface	Interface	500	$17.3	595
Wylie Ridge	Transformer	AP	$17.1	1,849
Cedar Grove - Roseland	Line	PSEG	($14.4)	657
Mount Storm - Pruntytown	Line	AP	$12.2	971
Branchburg - Readington	Line	PSEG	($7.7)	309
West	Interface	500	$6.7	307
Kanawha - Matt Funk	Line	AEP	$6.1	965
Beck - Middleport	Flowgate	Midwest ISO	($5.7)	61
Branchburg	Transformer	PSEG	$5.2	269
Absecon - Lewis	Line	AECO	$4.9	292
Cedar Grove - Clifton	Line	PSEG	($4.0)	274

Table 59 AECO Control Zone top congestion cost impacts (By facility): Planning period 2006 to 2007

Real Time Congestion Costs (Millions)				
Constraint	Type	Location	Load Congestion Costs	Event Hours
Laurel - Woodstown	Line	AECO	$31.0	891
Bedington - Black Oak	Interface	500	$29.9	1,676
Branchburg - Readington	Line	PSEG	($16.4)	794
Cloverdale - Lexington	Line	AEP	$14.6	1,589
5004/5005 Interface	Interface	500	$8.4	352
West	Interface	500	$6.4	374
Mount Storm - Pruntytown	Line	AP	$5.7	491
Wylie Ridge	Transformer	AP	$5.4	696
AP South	Interface	500	$4.8	158
Kammer	Transformer	500	$4.3	459
Deepwater	Transformer	AECO	$3.9	67
Cedar Grove - Roseland	Line	PSEG	($3.6)	329
Cedar Grove - Clifton	Line	PSEG	($3.5)	479
South Mahwah - Waldwick	Line	PSEG	$3.2	82
Loudoun - Morrisville	Line	Dominion	$2.9	87

Table 60 AECO Control Zone top congestion cost impacts (By facility): Planning period 2007 to 2008 through December 31, 2007

Real Time Congestion Costs (Millions)				
Constraint	Type	Location	Load Congestion Costs	Event Hours
Beckett - Paulsboro	Line	AECO	$23.4	417
Atlantic - Larrabee	Line	JCPL	($15.2)	463
Quinton - Roadstown	Line	AECO	$10.5	121
Kammer	Transformer	500	$9.5	1,270
West	Interface	500	$9.2	453
Cloverdale - Lexington	Line	AEP	$7.7	1,756
5004/5005 Interface	Interface	500	$7.1	398
AP South	Interface	500	$7.1	555
Branchburg - Readington	Line	PSEG	($6.5)	527
Bedington - Black Oak	Interface	500	$6.3	1,383
Cardiff	Transformer	AECO	$4.0	27
Sammis - Wylie Ridge	Line	AP	$3.1	370
Richmond - Waneeta	Line	PECO	$2.9	48
Wylie Ridge	Transformer	AP	$2.8	316
Conastone	Transformer	BGE	($2.7)	56

JCPL Control Zone

Table 61 through Table 63 shows the constraints with the largest impacts on total congestion cost in the JCPL Control Zone. In the 2005 to 2006 planning period, the Bedington – Black Oak Interface and the Kammer transformer were the largest contributors to positive congestion while the Cedar Grove — Roseland line and the Cedar Grove -- Clifton line contributed to negative congestion. In the 2006 to 2007 planning period, the Bedington – Black Oak Interface and the Cloverdale – Lexington line were the largest contributors to positive congestion while the Branchburg— Readington line and the Cedar Grove — Clifton line contributed most to negative congestion. In the 2007 to 2008 planning period, the Atlantic – Larrabee and Branchburg – Readington lines were the largest contributors to positive congestion costs while the Brunner Island – Yorkana line and Conastone transformer were the largest contributors to negative congestion costs.

Table 61 JCPL Control Zone top congestion cost impacts (By facility): Planning period 2005 to 2006

Real Time Congestion Costs (Millions)				
Constraint	Type	Location	Load Congestion Costs	Event Hours
Bedington - Black Oak	Interface	500	$53.0	1,966
Cedar Grove - Roseland	Line	PSEG	($52.4)	657
Kammer	Transformer	500	$42.3	1,805
5004/5005 Interface	Interface	500	$38.8	595
Doubs - Mount Storm	Line	500	$37.4	580
Branchburg	Transformer	PSEG	$36.5	269
Wylie Ridge	Transformer	AP	$35.1	1,849
Mount Storm - Pruntytown	Line	AP	$21.0	971
Cedar Grove - Clifton	Line	PSEG	($16.9)	274
West	Interface	500	$13.6	307
Beck - Middleport	Flowgate	Midwest ISO	($11.8)	61
Kanawha - Matt Funk	Line	AEP	$11.4	965
Branchburg - Readington	Line	PSEG	($7.1)	309
Cloverdale - Lexington	Line	AEP	$7.1	569
Waldwick	Transformer	PSEG	$5.9	44

Table 62 JCPL Control Zone top congestion cost impacts (By facility): Planning period 2006 to 2007

Real Time Congestion Costs (Millions)				
Constraint	Type	Location	Load Congestion Costs	Event Hours
Bedington - Black Oak	Interface	500	$53.2	1,676
Cloverdale - Lexington	Line	AEP	$27.2	1,589
Branchburg - Readington	Line	PSEG	($20.2)	794
5004/5005 Interface	Interface	500	$18.9	352
Branchburg - Flagtown	Line	PSEG	$17.0	117
Cedar Grove - Clifton	Line	PSEG	($14.0)	479
West	Interface	500	$13.2	374
Cedar Grove - Roseland	Line	PSEG	($13.1)	329
Wylie Ridge	Transformer	AP	$11.2	696
South Mahwah - Waldwick	Line	PSEG	$11.0	82
Mount Storm - Pruntytown	Line	AP	$9.5	491
AP South	Interface	500	$9.3	158
Kammer	Transformer	500	$9.1	459
Loudoun - Morrisville	Line	Dominion	$6.0	87
Muskingum River - Ohio Central	Line	AEP	($4.5)	25

Table 63 JCPL Control Zone top congestion cost impacts (By facility): Planning period 2007 to 2008 through December 31, 2007

Real Time Congestion Costs (Millions)				
Constraint	Type	Location	Load Congestion Costs	Event Hours
Atlantic - Larrabee	Line	JCPL	$58.8	463
Branchburg - Readington	Line	PSEG	$55.6	527
Kammer	Transformer	500	$19.8	1,270
West	Interface	500	$18.7	453
Branchburg - Flagtown	Line	PSEG	$18.6	96
5004/5005 Interface	Interface	500	$16.0	398
Cloverdale - Lexington	Line	AEP	$13.1	1,756
AP South	Interface	500	$11.6	555
Brunner Island - Yorkana	Line	Met-Ed	($6.7)	157
Sammis - Wylie Ridge	Line	AP	$6.3	370
East Towanda	Transformer	PENELEC	$6.3	716
Wylie Ridge	Transformer	AP	$5.7	316
Elrama - Mitchell	Line	AP	$4.5	798
Conastone	Transformer	BGE	($4.3)	56
MAAC - Scarcity	Interface	500	$3.9	3

PSEG Control Zone

Table 64 through

Table 66 shows the constraints with the largest impacts on total congestion cost in the PSEG Control Zone. In the 2005 to 2006 planning period, the Bedington – Black Oak Interface and the Kammer transformer were the largest contributors to positive congestion while the Beck – Middleport flowgate contributed to negative congestion. In the 2006 to 2007 planning period, the Bedington – Black Oak Interface and the Cloverdale – Lexington line were the largest contributors to positive congestion while the Muskingum River – Ohio Central line contributed to negative congestion. In the 2007 to 2008 planning period, the Branchburg – Readington line and the Kammer transformer were the largest contributors to positive congestion costs while the Brunner Island – Yorkana line and the Conastone transformer were the largest contributors to negative congestion costs.

Table 64 PSEG Control Zone top congestion cost impacts (By facility): Planning period 2005 to 2006

Real Time Congestion Costs (Millions)				
Constraint	Type	Location	Load Congestion Costs	Event Hours
Bedington - Black Oak	Interface	500	$95.6	1,966
Kammer	Transformer	500	$77.5	1,805
5004/5005 Interface	Interface	500	$66.9	595
Wylie Ridge	Transformer	AP	$65.9	1,849
Doubs - Mount Storm	Line	500	$65.6	580
Branchburg	Transformer	PSEG	$63.1	269
Mount Storm - Pruntytown	Line	AP	$38.0	971
West	Interface	500	$25.0	307
Beck - Middleport	Flowgate	Midwest ISO	($22.2)	61
Kanawha - Matt Funk	Line	AEP	$21.5	965
Cedar Grove - Clifton	Line	PSEG	$20.9	274
Cedar Grove - Roseland	Line	PSEG	$17.7	657
Cloverdale - Lexington	Line	AEP	$14.1	569
Waldwick	Transformer	PSEG	$13.2	44
Edison - Meadow Rd	Line	PSEG	$12.1	279

Table 65 PSEG Control Zone top congestion cost impacts (By facility): Planning period 2006 to 2007

Real Time Congestion Costs (Millions)				
Constraint	Type	Location	Load Congestion Costs	Event Hours
Bedington - Black Oak	Interface	500	$93.8	1,676
Cloverdale - Lexington	Line	AEP	$51.5	1,589
5004/5005 Interface	Interface	500	$31.7	352
West	Interface	500	$23.9	374
South Mahwah - Waldwick	Line	PSEG	$22.5	82
Branchburg - Readington	Line	PSEG	$22.2	794
Wylie Ridge	Transformer	AP	$20.7	696
Branchburg - Flagtown	Line	PSEG	$18.4	117
Mount Storm - Pruntytown	Line	AP	$17.9	491
Cedar Grove - Clifton	Line	PSEG	$17.5	479
Kammer	Transformer	500	$16.3	459
AP South	Interface	500	$15.9	158
Edison - Meadow Rd	Line	PSEG	$14.5	615
Loudoun - Morrisville	Line	Dominion	$10.3	87
Muskingum River - Ohio Central	Line	AEP	($7.5)	25

Table 66 PSEG Control Zone top congestion cost impacts (By facility): Planning period 2007 to 2008 through December 31, 2007

Real Time Congestion Costs (Millions)				
Constraint	Type	Location	Load Congestion Costs	Event Hours
Branchburg - Readington	Line	PSEG	$63.7	527
Kammer	Transformer	500	$35.5	1,270
West	Interface	500	$34.0	453
Atlantic - Larrabee	Line	JCPL	$32.6	463
5004/5005 Interface	Interface	500	$28.0	398
Cloverdale - Lexington	Line	AEP	$24.8	1,756
AP South	Interface	500	$20.2	555
Branchburg - Flagtown	Line	PSEG	$16.3	96
Sammis - Wylie Ridge	Line	AP	$11.4	370
Brunner Island - Yorkana	Line	Met-Ed	($11.3)	157
Wylie Ridge	Transformer	AP	$10.5	316
Elrama - Mitchell	Line	AP	$8.4	798
Conastone	Transformer	BGE	($7.9)	56
East Towanda	Transformer	PENELEC	$6.6	716
MAAC - Scarcity	Interface	500	$6.6	3

RECO Control ZoneTable 67 through Table 69 shows the constraints with the largest impacts on total congestion cost in the RECO Control Zone. In the 2005 to 2006 planning period, the Bedington – Black Oak Interface and the Cedar Grove — Roseland line were the largest contributors to positive congestion while the Beck – Widdleport flowgate and the Waldwick transformer contributed to negative congestion. In the 2006 to 2007 planning period, the Bedington – Black Oak Interface and the Branchburg – Readington line were the largest contributors to positive congestion while the South Mahwah – Waldwick and Muskingum River – Ohio Central lines contributed to negative congestion. In the 2007 to 2008 planning period, the Branchburg – Readington and Atlantic Larrabee lines were the largest contributors to positive congestion costs while the Bedington – Black Oak interface and Brunner Island – Yorkana line were the largest contributors to negative congestion costs.

Table 67 RECO Control Zone top congestion cost impacts (By facility): Planning period 2005 to 2006

Real Time Congestion Costs (Millions)				
Constraint	Type	Location	Load Congestion Costs	Event Hours
Bedington - Black Oak	Interface	500	$2.6	1,966
Cedar Grove - Roseland	Line	PSEG	$2.3	657
Kammer	Transformer	500	$2.3	1,805
5004/5005 Interface	Interface	500	$2.1	595
Doubs - Mount Storm	Line	500	$2.0	580
Wylie Ridge	Transformer	AP	$1.9	1,849
Branchburg - Readington	Line	PSEG	$1.2	309
Mount Storm - Pruntytown	Line	AP	$1.1	971
Beck - Middleport	Flowgate	Midwest ISO	($0.8)	61
Branchburg	Transformer	PSEG	$0.8	269
West	Interface	500	$0.7	307
Kanawha - Matt Funk	Line	AEP	$0.6	965
Waldwick	Transformer	PSEG	($0.5)	44
Cedar Grove - Clifton	Line	PSEG	$0.4	274
Cloverdale - Lexington	Line	AEP	$0.4	569

Table 68 RECO Control Zone top congestion cost impacts (By facility): Planning period 2006 to 2007

Real Time Congestion Costs (Millions)				
Constraint	Type	Location	Load Congestion Costs	Event Hours
Bedington - Black Oak	Interface	500	$2.6	1,676
Branchburg - Readington	Line	PSEG	$2.5	794
Cloverdale - Lexington	Line	AEP	$1.4	1,589
5004/5005 Interface	Interface	500	$1.0	352
South Mahwah - Waldwick	Line	PSEG	($0.7)	82
West	Interface	500	$0.7	374
Wylie Ridge	Transformer	AP	$0.6	696
Cedar Grove - Roseland	Line	PSEG	$0.6	329
AP South	Interface	500	$0.5	158
Mount Storm - Pruntytown	Line	AP	$0.5	491
Kammer	Transformer	500	$0.5	459
Branchburg - Flagtown	Line	PSEG	$0.4	117
Cedar Grove - Clifton	Line	PSEG	$0.4	479
Loudoun - Morrisville	Line	Dominion	$0.4	87
Muskingum River - Ohio Central	Line	AEP	($0.3)	25

Table 69 RECO Control Zone top congestion cost impacts (By facility): Planning period 2007 to 2008 through December 31, 2007

Real Time Congestion Costs (Millions)				
Constraint	Type	Location	Load Congestion Costs	Event Hours
Branchburg - Readington	Line	PSEG	$4.0	527
Atlantic - Larrabee	Line	JCPL	$1.4	463
Kammer	Transformer	500	$1.1	1,270
West	Interface	500	$0.9	453
5004/5005 Interface	Interface	500	$0.9	398
Cloverdale - Lexington	Line	AEP	$0.6	1,756
Bedington - Black Oak	Interface	500	($0.5)	1,383
AP South	Interface	500	$0.4	555
Brunner Island - Yorkana	Line	Met-Ed	($0.4)	157
Cedar Grove - Roseland	Line	PSEG	$0.3	122
Wylie Ridge	Transformer	AP	$0.3	316
Sammis - Wylie Ridge	Line	AP	$0.3	370
Branchburg - Flagtown	Line	PSEG	$0.3	96
MAAC - Scarcity	Interface	500	$0.3	3
Athenia - Saddlebrook	Line	PSEG	$0.3	72

Financial Transmission and Auction Revenue Rights

Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs) give transmission service customers and PJM members a hedge against congestion costs in the Day-Ahead Energy Market. An FTR provides the holder with revenues, or charges, equal to the difference in congestion prices in the Day-Ahead Energy Market across the specific FTR transmission path. An ARR is a related product that provides the holder with revenues, or charges, based on the price differences across the specific ARR transmission path that result from the Annual FTR Auction. FTRs and ARRs provide a hedge against congestion costs, but neither FTRs nor ARRs provide a guarantee that transmission service customers will not pay congestion charges. ARR and FTR holders do not need to physically deliver energy to receive ARR or FTR credits and neither instrument represents a right to the physical delivery of energy.

Firm transmission service customers have access to ARRs/FTRs because they pay the costs of the transmission system that enables firm energy delivery. Firm transmission service customers receive requested ARRs/FTRs to the extent that they are consistent both with the physical capability of the transmission system and with ARR/FTR requests of other eligible customers.

Financial Transmission Rights

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the Day-Ahead Energy Market across specific FTR transmission paths. Effective June 1, 2007, PJM added marginal losses as a component in the calculation of LMP. The value of an FTR reflects the difference in congestion prices rather than the difference in LMPs, which includes both congestion and marginal losses. Auction market participants are free to request FTRs between any pricing nodes on the system, including hubs, control zones, aggregates, generator buses, load buses and interface pricing points. FTRs are available to the nearest 0.1 MW. The FTR target allocation is calculated hourly and is equal to the product of the FTR MW and the congestion price difference between sink and source that occurs in the Day-Ahead Energy Market. The value of an FTR can be positive or negative depending on the sink-minus-source congestion price difference, with a negative difference resulting in a liability for the holder. The FTR target allocation represents what the holders should receive if sufficient revenues are collected to fund FTRs.

Depending on the amount of FTR revenues collected, FTR holders with a positively valued FTR may receive congestion credits between zero and their target allocations. FTR holders with a negatively valued FTR are required to pay charges equal to their target allocations. When FTR holders receive their target allocations, the associated FTRs are fully funded. The objective function of all FTR auctions is to maximize the bid-based value of FTRs awarded in each auction.

Patterns of Ownership

In order to evaluate the ownership of prevailing flow and counterflow FTRs, the MMU categorized all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. The MMU used available public information to categorize FTR owners and while the distinctions are not perfect, they are accurate enough to support some general conclusions. Table 70 presents the Annual FTR Auction market concentration for cleared FTRs in the 2005 to 2006, the 2006 to 2007 and the 2007 to 2008 planning periods by control zone, organization type and FTR direction.

Table 70 Annual FTR Auction patterns of ownership by FTR direction: Planning periods 2005 to 2006, 2006 to 2007 and 2007 to 2008

				FTR Direction		
State	Planning Period	Control Zone	Organization Type	Prevailing Flow	Counterflow	All
NJ	2005/2006	AECO	Physical	49.6%	31.7%	48.3%
			Financial	50.4%	68.3%	51.7%
			Total	100.0%	100.0%	100.0%
		JCPL	Physical	34.1%	71.7%	37.4%
			Financial	65.9%	28.3%	62.6%
			Total	100.0%	100.0%	100.0%
		PSEG	Physical	53.3%	62.6%	55.3%
			Financial	46.7%	37.4%	44.7%
			Total	100.0%	100.0%	100.0%
		RECO	Physical	56.1%	79.2%	59.3%
			Financial	43.9%	20.8%	40.7%
			Total	100.0%	100.0%	100.0%
	2006/2007	AECO	Physical	44.5%	14.3%	41.0%
			Financial	55.5%	85.7%	59.0%
			Total	100.0%	100.0%	100.0%
		JCPL	Physical	27.1%	56.4%	35.0%
			Financial	72.9%	43.6%	65.0%
			Total	100.0%	100.0%	100.0%
		PSEG	Physical	55.9%	25.3%	50.7%
			Financial	44.1%	74.7%	49.3%
			Total	100.0%	100.0%	100.0%
		RECO	Physical	30.1%	86.6%	34.7%
			Financial	69.9%	13.4%	65.3%
			Total	100.0%	100.0%	100.0%
	2007/2008	AECO	Physical	39.0%	2.1%	27.3%
			Financial	61.0%	97.9%	72.7%
			Total	100.0%	100.0%	100.0%
		JCPL	Physical	29.0%	22.3%	27.0%
			Financial	71.0%	77.7%	73.0%
			Total	100.0%	100.0%	100.0%
		PSEG	Physical	29.7%	20.6%	27.2%
			Financial	70.3%	79.4%	72.8%
			Total	100.0%	100.0%	100.0%
		RECO	Physical	55.2%	32.1%	47.7%
			Financial	44.8%	67.9%	52.3%
			Total	100.0%	100.0%	100.0%

Market Performance

Volume

Table 71 shows the Annual FTR Auction volume by control zone and trade type for the 2005 to 2006, the 2006 to 2007 and the 2007 to 2008 planning periods.

Table 71 Annual FTR Auction market volume: Planning periods 2005 to 2006, 2006 to 2007 and 2007 to 2008

State	Planning Period	Control Zone	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
NJ	2005/2006	AECO	Buy bids	158,273	26,351.8	3,428.9	13.0%	22,922.8	87.0%
			Self-scheduled bids	48,412	277.3	277.3	100.0%	0.0	0.0%
			Sell offers	32,287	2,077.2	46.2	2.2%	2,031.0	97.8%
		JCPL	Buy bids	133,521	19,831.5	6,794.9	34.3%	13,036.6	65.7%
			Self-scheduled bids	54,708	672.5	672.5	100.0%	0.0	0.0%
			Sell offers	42,925	3,062.1	74.7	2.4%	2,987.4	97.6%
		PSEG	Buy bids	406,258	49,939.5	9,721.2	19.5%	40,218.2	80.5%
			Self-scheduled bids	108,900	265.5	265.5	100.0%	0.0	0.0%
			Sell offers	137,446	3,771.7	341.2	9.0%	3,430.5	91.0%
		RECO	Buy bids	8,704	4,871.0	673.2	13.8%	4,197.8	86.2%
			Self-scheduled bids	128	1.4	1.4	100.0%	0.0	0.0%
			Sell offers	704	133.7	39.7	29.7%	94.0	70.3%
	2006/2007	AECO	Buy bids	271,030	64,643.2	5,407.3	8.4%	59,235.9	91.6%
			Self-scheduled bids	21,840	67.9	67.9	100.0%	0.0	0.0%
			Sell offers	30,619	3,089.3	220.5	7.1%	2,868.8	92.9%
		JCPL	Buy bids	225,381	53,494.6	9,099.1	17.0%	44,395.5	83.0%
			Self-scheduled bids	59,660	768.9	768.9	100.0%	0.0	0.0%
			Sell offers	21,202	6,567.2	166.0	2.5%	6,401.1	97.5%
		PSEG	Buy bids	760,653	163,362.6	7,855.2	4.8%	155,507.5	95.2%
			Self-scheduled bids	242,824	473.0	473.0	100.0%	0.0	0.0%
			Sell offers	39,388	3,581.0	341.4	9.5%	3,239.7	90.5%
		RECO	Buy bids	10,422	9,801.4	833.6	8.5%	8,967.8	91.5%
			Self-scheduled bids	0	0.0	0.0	NA	0.0	NA
			Sell offers	270	247.8	0.0	0.0%	247.8	100.0%
	2007/2008	AECO	Buy bids	406,586	83,284.8	10,325.5	12.4%	72,959.3	87.6%
			Self-scheduled bids	13,544	186.9	186.9	100.0%	0.0	0.0%
			Sell offers	56,214	5,742.8	284.7	5.0%	5,458.1	95.0%
		JCPL	Buy bids	452,112	123,378.6	11,970.6	9.7%	111,408.0	90.3%
			Self-scheduled bids	44,460	1,076.4	1,076.4	100.0%	0.0	0.0%
			Sell offers	8,276	5,008.1	358.5	7.2%	4,649.6	92.8%
		PSEG	Buy bids	1,036,783	138,766.8	18,726.6	13.5%	120,040.2	86.5%
			Self-scheduled bids	114,720	525.5	525.5	100.0%	0.0	0.0%
			Sell offers	33,223	8,115.8	477.6	5.9%	7,638.2	94.1%
		RECO	Buy bids	12,438	9,545.2	708.9	7.4%	8,836.3	92.6%
			Self-scheduled bids	0	0.0	0.0	NA	0.0	NA
			Sell offers	360	93.0	0.0	0.0%	93.0	100.0%

Table 72 shows self-scheduled FTR data by control zone for the 2005 to 2006, the 2006 to 2007 and the 2007 to 2008 planning periods.

Table 72 Comparison of self-scheduled FTRs: Planning periods 2005 to 2006, 2006 to 2007 and 2007 to 2008

State	Planning Period	Control Zone	Self-Scheduled FTRs (MW)	Maximum Possible Self-Scheduled FTRs (MW)	Percent of ARRs Self-Scheduled as FTRs
NJ	2005/2006	AECO	277.3	1,856.9	14.9%
		JCPL	672.5	2,330.3	28.9%
		PSEG	265.5	5,974.5	4.4%
		RECO	1.4	104.0	1.3%
	2006/2007	AECO	67.9	2,240.1	3.0%
		JCPL	768.9	2,523.7	30.5%
		PSEG	473.0	5,055.0	9.4%
		RECO	0.0	246.1	0.0%
	2007/2008	AECO	186.9	2,258.3	8.3%
		JCPL	1,076.4	3,065.5	35.1%
		PSEG	525.5	5,065.6	10.4%
		RECO	0.0	401.1	0.0%

Figure 9 through Figure 12 show the bid and cleared volume for FTRs in the Monthly FTR Auctions for each control zone by month for June 2005 through December 2007

Figure 9 Monthly FTR auction bid and cleared volume (MW) in the AECO Control Zone: June 2005 to December 2007

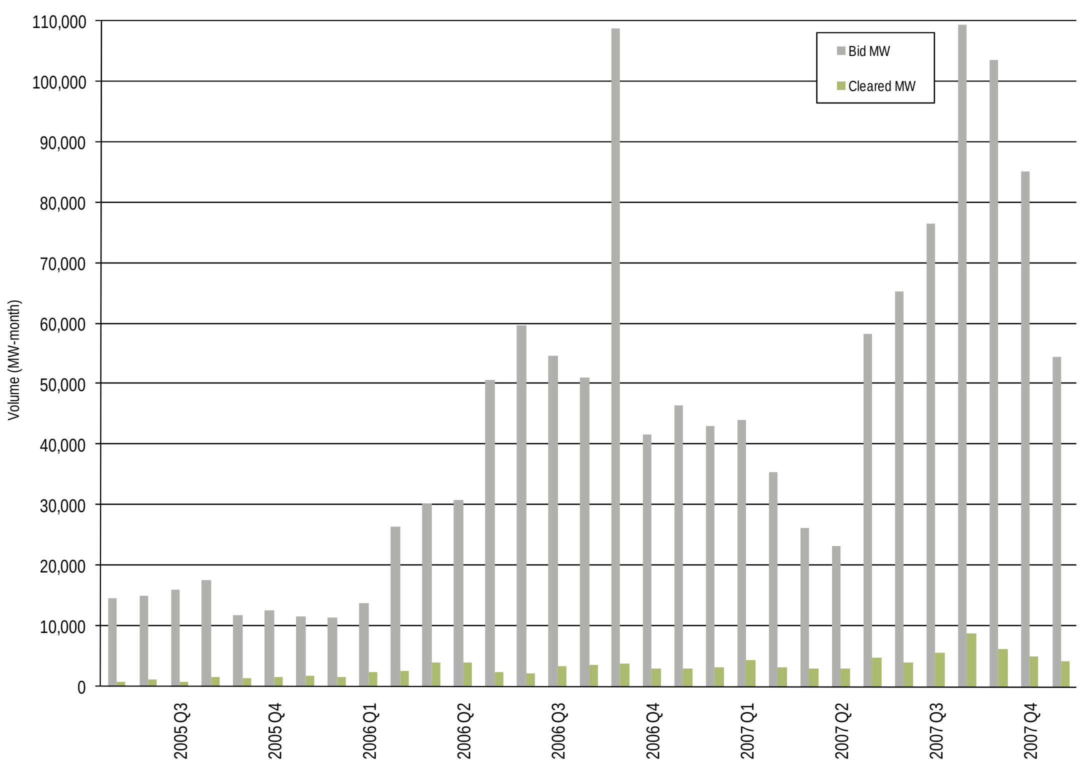

Figure 10 Monthly FTR auction bid and cleared volume (MW) in the JCPL Control Zone: June 2005 to December 2007

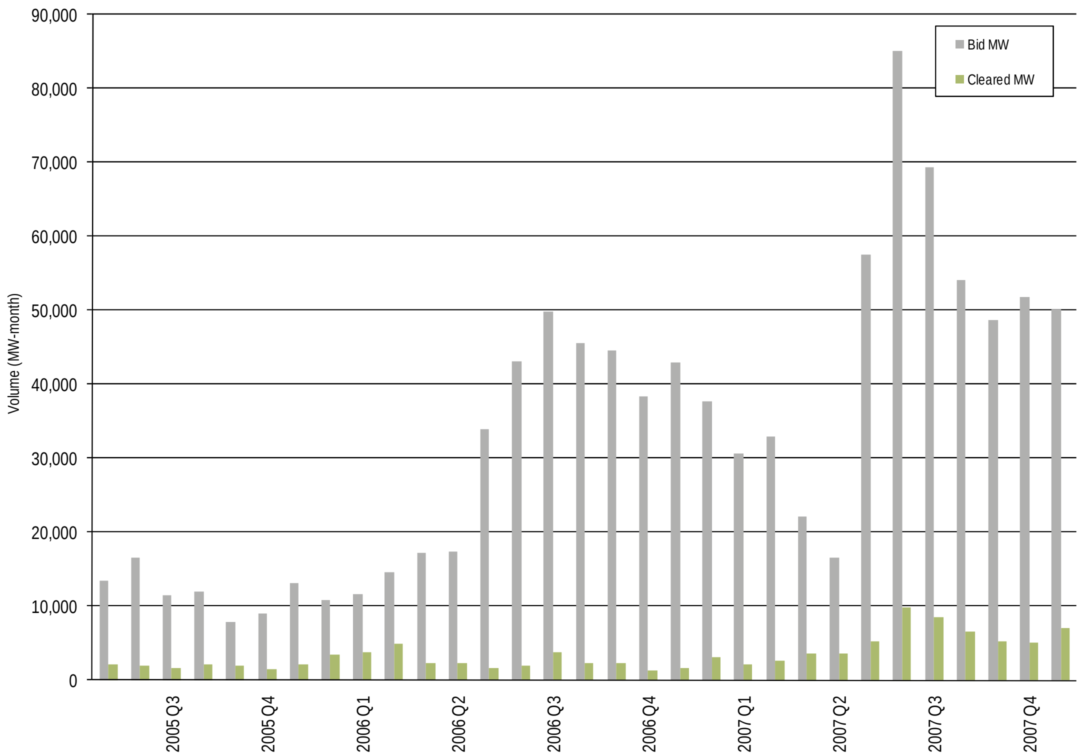

Figure 11 Monthly FTR auction bid and cleared volume (MW) in the PSEG Control Zone: June 2005 to December 2007

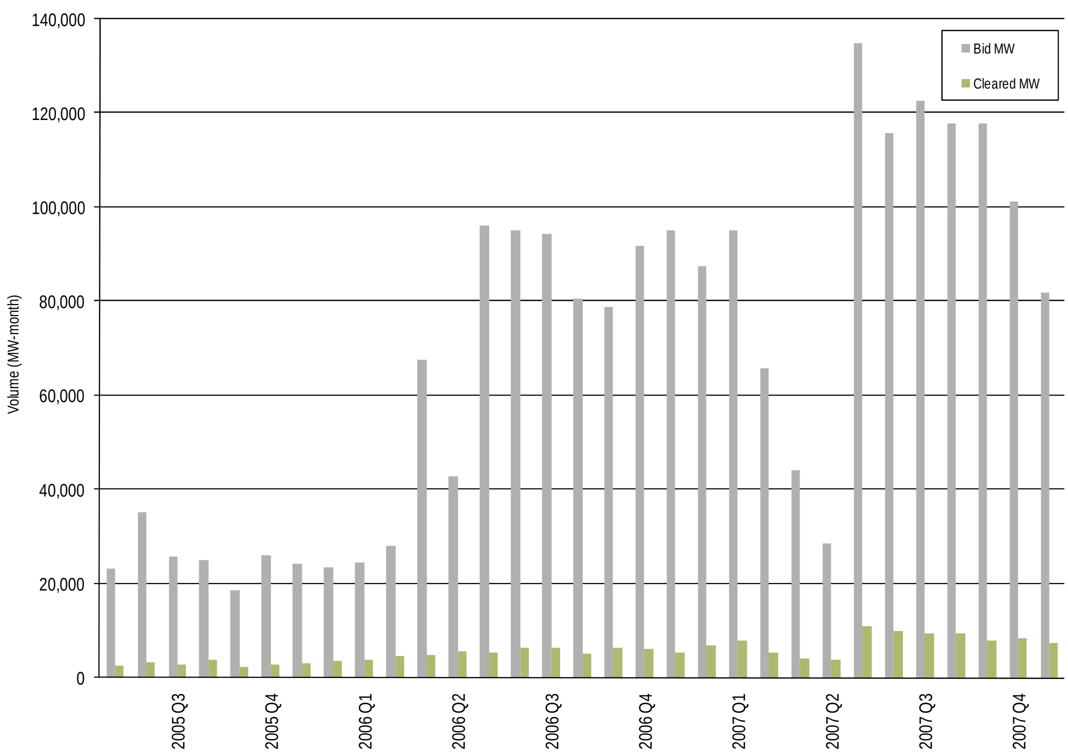

Figure 12 Monthly FTR auction bid and cleared volume (MW) in the RECO aggregate: June 2005 to December 2007

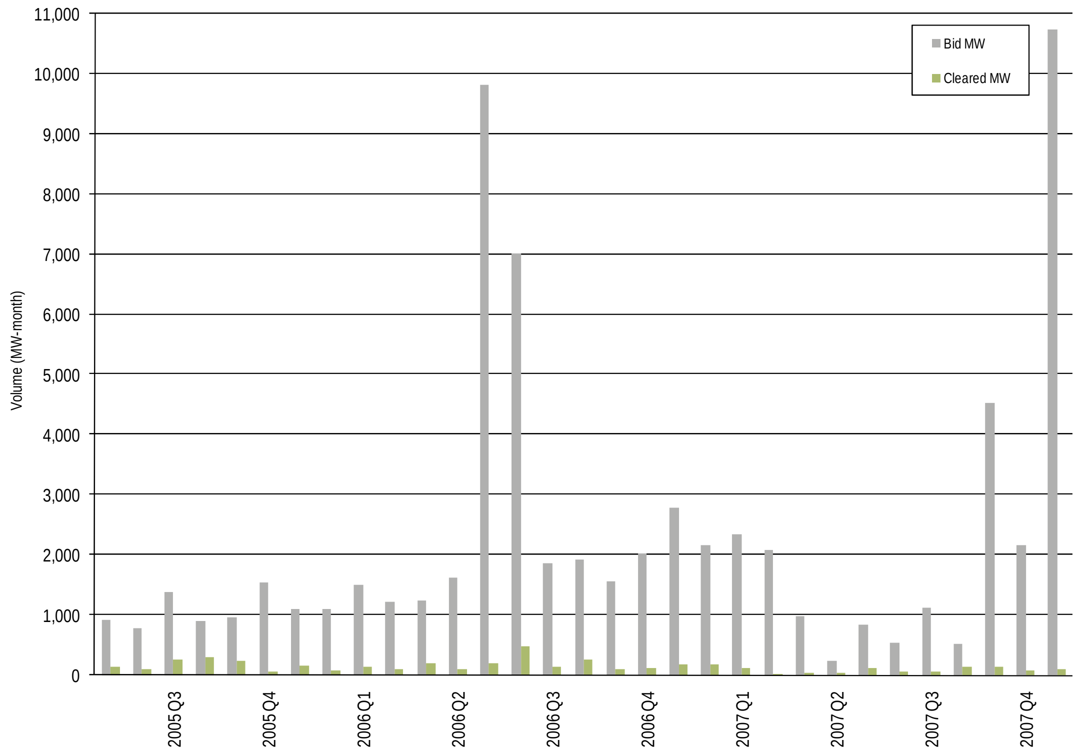

Table 73 shows the secondary bilateral FTR market volume by control zone, hedge type and class type for the 2005 to 2006, the 2006 to 2007 and the 2007 to 2008 planning periods.

Table 73 Secondary bilateral FTR market volume: Planning periods 2005 to 2006, 2006 to 2007 and 2007 to 2008[42]

			Class Type			
Planning Period	Control Zone	Hedge Type	24-Hour	On Peak	Off Peak	All
2005/2006	AECO	Obligation	29,210.5	6,063.4	226.7	35,500.6
		Option	0.0	125.6	3,713.0	3,838.6
	JCPL	Obligation	10,611.8	4,813.2	206.9	15,631.9
		Option	0.0	2,778.8	9,667.5	12,446.3
	PSEG	Obligation	15,367.5	17,086.1	15,684.3	48,137.9
		Option	0.0	942.0	2,422.5	3,364.5
	RECO	Obligation	0.0	1,192.0	320.0	1,512.0
		Option	0.0	0.0	0.0	0.0
2006/2007	AECO	Obligation	3,538.8	1,230.1	647.0	5,415.9
		Option	0.0	0.0	0.0	0.0
	JCPL	Obligation	0.0	21.0	0.0	21.0
		Option	0.0	0.0	0.0	0.0
	PSEG	Obligation	0.0	52.3	253.0	305.3
		Option	0.0	0.0	0.0	0.0
	RECO	Obligation	0.0	0.0	0.0	0.0
		Option	0.0	0.0	0.0	0.0
2007/2008	AECO	Obligation	4.6	240.9	0.0	245.5
		Option	0.0	20.0	25.2	45.2
	JCPL	Obligation	0.0	14,925.0	0.0	14,925.0
		Option	0.0	19,304.0	6,488.0	25,792.0
	PSEG	Obligation	0.0	28,867.1	0.0	28,867.1
		Option	0.0	0.0	135.0	135.0
	RECO	Obligation	0.0	0.0	0.0	0.0
		Option	0.0	0.0	0.0	0.0

42 The 2007 to 2008 planning period covers the 2007 to 2008 Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions through December 31, 2007.

Price

Table 74 shows the weighted-average bid price by control zone, trade type and class type in the Annual FTR Auction for the 2005 to 2006, the 2006 to 2007 and the 2007 to 2008 planning period.

Table 74 Annual FTR Auction weighted-average bid prices (Dollars per MWh): Planning periods 2005 to 2006, 2006 to 2007 and 2007 to 2008

			Class Type			
Planning Period	Control Zone	Trade Type	24-Hour	On Peak	Off Peak	All
2005/2006	AECO	Buy bids	$1.93	$0.61	$0.31	$0.82
		Sell offers	($1.43)	($2.11)	($0.87)	($1.39)
	JCPL	Buy bids	$2.45	$0.61	$0.41	$1.01
		Sell offers	($1.98)	($0.21)	($0.29)	($0.54)
	PSEG	Buy bids	$2.12	$2.01	$0.62	$1.61
		Sell offers	($0.76)	($0.48)	($0.42)	($0.63)
	RECO	Buy bids	$1.79	$1.03	$0.42	$0.81
		Sell offers	($2.41)	($1.20)	($1.04)	($1.20)
2006/2007	AECO	Buy bids	$2.58	($1.41)	($0.50)	($0.57)
		Sell offers	($0.69)	($2.62)	($1.21)	($1.78)
	JCPL	Buy bids	$3.61	$0.09	($0.61)	$0.30
		Sell offers	$0.38	($0.64)	($0.28)	($0.43)
	PSEG	Buy bids	$3.77	($0.58)	($0.96)	($0.30)
		Sell offers	($1.33)	($2.22)	($1.47)	($1.84)
	RECO	Buy bids	$0.22	$0.66	$0.35	$0.44
		Sell offers	NA	($0.31)	($0.09)	($0.13)
2007/2008	AECO	Buy bids	$0.99	($0.96)	($0.52)	($0.35)
		Sell offers	($2.26)	($0.33)	($0.46)	($0.93)
	JCPL	Buy bids	$0.80	$0.02	($0.29)	($0.01)
		Sell offers	($4.83)	($1.02)	($0.32)	($0.82)
	PSEG	Buy bids	$2.03	$0.66	$0.23	$0.77
		Sell offers	($3.21)	($1.78)	($0.62)	($1.56)
	RECO	Buy bids	$0.90	$0.80	$0.36	$0.63
		Sell offers	($2.20)	($2.15)	$0.47	($1.71)

Table 75 shows the cleared, weighted-average prices by control zone, trade type, hedge type and class type for annual FTRs during the 2005 to 2006, the 2006 to 2007 and the 2007 to 2008 planning period.

Table 75 Annual FTR Auction weighted-average cleared prices (Dollars per MWh): Planning periods 2005 to 2006, 2006 to 2007 and 2007 to 2008

				Class Type			
Planning Period	Control Zone	Trade Type	Hedge Type	24-Hour	On Peak	Off Peak	All
2005/2006	AECO	Buy	Obligation	$2.22	$2.52	$0.58	$1.87
			Option	$0.28	$0.66	$0.17	$0.32
		Self-scheduled bids	Obligation	$2.55	NA	NA	$2.55
		Sell offers	Obligation	NA	($1.78)	($1.17)	($1.44)
			Option	NA	NA	NA	NA
	JCPL	Buy	Obligation	$2.38	$3.05	$0.98	$2.27
			Option	$0.51	$0.06	$0.06	$0.06
		Self-scheduled bids	Obligation	$2.48	NA	NA	$2.48
		Sell offers	Obligation	($2.18)	($0.02)	($0.19)	($1.21)
			Option	NA	($0.06)	($0.03)	($0.04)
	PSEG	Buy	Obligation	$1.81	$3.83	$0.83	$2.12
			Option	$0.51	$1.42	$0.55	$1.06
		Self-scheduled bids	Obligation	$2.55	NA	NA	$2.55
		Sell offers	Obligation	($0.79)	$0.13	$0.06	($0.49)
			Option	NA	NA	NA	NA
	RECO	Buy	Obligation	($0.02)	$2.61	$1.39	$1.62
			Option	NA	$0.18	$0.14	$0.16
		Self-scheduled bids	Obligation	$4.89	NA	NA	$4.89
		Sell offers	Obligation	($3.82)	($1.22)	($1.05)	($1.18)
			Option	NA	($0.05)	NA	($0.05)
2006/2007	AECO	Buy	Obligation	$2.64	$2.16	$0.38	$1.99
			Option	$0.00	$2.14	$0.71	$1.30
		Self-scheduled bids	Obligation	$5.33	NA	NA	$5.33
		Sell offers	Obligation	($0.30)	$1.69	$0.87	$1.04
			Option	NA	($0.28)	($0.07)	($0.29)
	JCPL	Buy	Obligation	$4.92	$1.37	($0.01)	$2.19
			Option	NA	$0.33	$0.14	$0.22
		Self-scheduled bids	Obligation	$2.16	NA	NA	$2.16
		Sell offers	Obligation	$0.78	$0.67	$1.24	$1.01
			Option	NA	NA	($0.29)	($0.29)
	PSEG	Buy	Obligation	$5.28	$3.13	$1.48	$3.81
			Option	NA	$0.72	$0.91	$0.85
		Self-scheduled bids	Obligation	$3.98	NA	NA	$3.98
		Sell offers	Obligation	($1.19)	($0.95)	($1.56)	($1.23)
			Option	NA	NA	($1.98)	($1.98)
	RECO	Buy	Obligation	$1.27	$1.17	$0.92	$1.10
			Option	$0.03	$0.10	$0.18	$0.16
		Self-scheduled bids	Obligation	NA	NA	NA	NA
		Sell offers	Obligation	NA	NA	NA	NA
			Option	NA	NA	NA	NA
2007/2008	AECO	Buy	Obligation	$1.71	($0.38)	($0.29)	$0.31
			Option	$2.07	$2.06	$0.58	$1.28
		Self-scheduled bids	Obligation	$2.04	NA	NA	$2.04
		Sell offers	Obligation	($2.15)	$1.03	$0.86	($0.40)
			Option	NA	($1.17)	($0.31)	($0.35)
	JCPL	Buy	Obligation	$1.04	$1.70	$0.43	$1.10
			Option	$1.39	$1.15	$0.20	$0.94
		Self-scheduled bids	Obligation	$0.93	NA	NA	$0.93
		Sell offers	Obligation	NA	$1.26	$0.41	$0.81
			Option	NA	($1.12)	NA	($1.12)
	PSEG	Buy	Obligation	$2.39	$1.92	$1.09	$1.84
			Option	$1.39	$3.58	$3.84	$3.66
		Self-scheduled bids	Obligation	$3.34	NA	NA	$3.34
		Sell offers	Obligation	($0.70)	$0.74	$0.12	$0.19
			Option	NA	NA	NA	NA
	RECO	Buy	Obligation	$0.75	$2.34	$0.46	$1.03
			Option	NA	NA	$0.64	$0.64
		Self-scheduled bids	Obligation	NA	NA	NA	NA
		Sell offers	Obligation	NA	NA	NA	NA
			Option	NA	NA	NA	NA

Revenue

Table 76 shows Annual FTR Auction revenue data by control zone, trade type and class type for the 2005 to 2006, the 2006 to 2007 and the 2007 to 2008 planning periods.

Table 76 Annual FTR Auction revenue: Planning periods 2005 to 2006, 2006 to 2007 and 2007 to 2008

			Class Type			
Planning Period	Control Zone	Trade Type	24-Hour	On Peak	Off Peak	All
2005/2006	AECO	Buy bids	$17,731,481	$9,696,998	$2,682,733	$30,111,211
		Self-scheduled bids	$6,195,312	NA	NA	$6,195,312
		Sell offers	$0	($161,821)	($130,943)	($292,764)
	JCPL	Buy bids	$22,474,106	$9,766,947	$3,082,035	$35,323,088
		Self-scheduled bids	$14,616,088	NA	NA	$14,616,088
		Sell offers	($247,712)	($3,472)	($14,360)	($265,544)
	PSEG	Buy bids	$49,057,722	$57,189,259	$10,800,548	$117,047,529
		Self-scheduled bids	$5,922,896	NA	NA	$5,922,896
		Sell offers	($1,162,544)	$55,764	$20,110	($1,086,670)
	RECO	Buy bids	($9,346)	$2,363,914	$933,759	$3,288,327
		Self-scheduled bids	$59,987	NA	NA	$59,987
		Sell offers	($6,687)	($86,736)	($51,404)	($144,828)
2006/2007	AECO	Buy bids	$31,200,072	$18,403,493	$4,731,834	$54,335,399
		Self-scheduled bids	$3,173,244	NA	NA	$3,173,244
		Sell offers	($69,884)	$892,062	$168,421	$990,599
	JCPL	Buy bids	$36,178,677	$14,187,515	$1,578,831	$51,945,023
		Self-scheduled bids	$14,529,947	NA	NA	$14,529,947
		Sell offers	$24,598	$165,097	$463,330	$653,025
	PSEG	Buy bids	$111,813,629	$41,048,985	$14,836,017	$167,698,631
		Self-scheduled bids	$16,498,862	NA	NA	$16,498,862
		Sell offers	($919,180)	($428,356)	($1,120,740)	($2,468,275)
	RECO	Buy bids	$631,223	$752,311	$958,022	$2,341,556
		Self-scheduled bids	$0	NA	NA	$0
		Sell offers	$0	$0	$0	$0
2007/2008	AECO	Buy bids	$26,899,343	($1,560,041)	($3,130,099)	$22,209,203
		Self-scheduled bids	$3,349,415	NA	NA	$3,349,415
		Sell offers	($1,191,105)	$455,224	$134,072	($601,810)
	JCPL	Buy bids	$19,341,668	$39,717,426	$7,208,982	$66,268,077
		Self-scheduled bids	$8,819,219	NA	NA	$8,819,219
		Sell offers	$0	$679,936	$307,146	$987,082
	PSEG	Buy bids	$84,802,675	$65,979,774	$33,887,567	$184,670,016
		Self-scheduled bids	$15,426,543	NA	NA	$15,426,543
		Sell offers	($350,546)	$688,777	$111,504	$449,735
	RECO	Buy bids	$1,082,339	$1,960,909	$799,952	$3,843,200
		Self-scheduled bids	$0	NA	NA	$0
		Sell offers	$0	$0	$0	$0

Auction Revenue Rights

FTRs and ARRs are both financial instruments that entitle the holder to receive revenues or to pay charges based on nodal price differences. FTRs provide holders with revenues or charges based on the locational congestion price differences actually experienced in the Day-Ahead Energy Market while ARRs are financial instruments that entitle their holders to receive revenue or to pay charges based on prices determined in the Annual FTR Auction.[43] These price differences are based on the bid prices of participants in the Annual FTR Auction which relate to their expectations about the level of congestion in the Day-Ahead Energy Market. The auction clears the set of feasible FTR bids which produce the highest net revenue. In other words, ARR revenues are a function of FTR auction participants' expectations of locational congestion price differences in the Day-Ahead Energy Market.

ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to the product of the ARR MW and the price difference between sink and source from the Annual FTR Auction. An ARR value can be positive or negative depending on the sink-minus-source price difference, with a negative difference resulting in a liability for the holder. The ARR target allocation represents the revenue that an ARR holder should receive. All ARR holders receive ARR credits equal to their target allocations if total net revenues from the Annual and Monthly Balance of Planning Period FTR Auctions are greater than, or equal to, the sum of all ARR target allocations. ARR credits can be positive or negative and can range from zero to the ARR target allocation. If the combined net revenues from the Annual and Monthly Balance of Planning Period FTR Auctions are less than that, available revenue is proportionally allocated among all ARR holders.

Auction Revenue Right (ARR) Allocation

PJM conducts the annual ARR allocation in March of every year for the upcoming planning period. The final results of the annual ARR allocation are available in early April.

ARRs provide their holders with revenues, or charges, based on the price differences across the specific ARR transmission path that result from the Annual FTR Auction. Network service and firm, point-to-point transmission service customers request ARRs to the control zone or load aggregation zone where they serve load. The annual ARR allocation for the 2005 to 2006 and the 2006 to 2007 planning periods was a five-round procedure:

– **Stage 1.** In the first stage of the allocation, network service customers can obtain ARRs, up to their peak-load share, based on generation resources that historically have served load in each control zone or load aggregation zone. Firm, point-to-point transmission service customers can obtain ARRs based on the MW of firm, long-

[43] These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces the most net revenue.

term, point-to-point transmission service provided between the receipt and delivery points for the historical reference year.

– **Stage 2.** The second stage of the allocation is a four-step procedure, with 25 percent of the remaining system capability allocated in each step of the process. Network service customers can obtain ARRs from any generator bus, hub, control zone or interface to any part of their load in a control zone or load aggregation zone for which an ARR was not allocated in the first stage. Firm, point-to-point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1.

For the 2007 to 2008 planning period, the annual ARR allocation was revised to include long-term ARRs while maintaining a five-round procedure:

– **Stage 1A.** In the first stage of the allocation, network service customers can obtain long-term ARRs, up to their share of the zonal baseload, after taking into account generation resources that historically have served load in each control zone and up to 50 percent of their historical nonzone network load. Nonzone network load is load that is located outside of the PJM footprint. Firm, point-to-point transmission service customers can obtain long-term ARRs, based on up to 50 percent of the MW of long-term, firm, point-to-point transmission service provided between the receipt and delivery points for the historical reference year.

– **Stage 1B.** ARRs unallocated in Stage 1A are available in the Stage 1B allocation. Network service customers can obtain ARRs, up to their share of the zonal peak load, based on generation resources that historically have served load in each control zone and up to 100 percent of their transmission responsibility for nonzone network load. Firm, point-to-point transmission service customers can obtain ARRs based on the MW of firm, long-term, point-to-point service provided between the receipt and delivery points for the historical reference year.

– **Stage 2.** The third stage of the annual ARR allocation is a three-step procedure, with one-third of the remaining system capability allocated in each step of the process. Network service customers can obtain ARRs from any generator bus, hub, control zone or interface pricing point to any part of their load in a control zone or load aggregation zone for which an ARR was not allocated in Stage 1A or Stage 1B. Firm, point-to-point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

The winners of load in the BGS auctions can request ARRs to the control zone or load aggregation zone where they serve load. All ARR requests will be evaluated for simultaneous feasibility to ensure that the physical transmission system can support the cleared set of ARRs. Cleared ARRs may be self-scheduled in full or in part into FTRs during the first round of the Annual FTR Auction which starts in April of every year.

These ARRs and self-scheduled FTRs serve as a hedge against congestion costs for the BGS auction winners.

Table 77 shows the ARR requested and cleared MW, ARR credits, self-scheduled FTR MW and credits, total hedge, and real-time BGS related energy charges and the percentage of total energy charges offset by ARR and self-scheduled FTR credits, based on a peak network load pro rata share, within the AECO, JCPL, PSEG, and RECO zones in the state of New Jersey.

The ARR credits do not include the credits for the portion of any ARR that was self-scheduled as an FTR since ARR holders purchase self-scheduled FTRs in the Annual FTR Auction and that revenue is then paid back to the ARR holders, netting the transaction to zero. ARR credits are calculated as the product of the ARR MW (excludes any self-scheduled FTR MW) and the sink-minus-source price difference for the ARR path from the Annual FTR Auction. The self-scheduled FTR credits are calculated as the product of the self-scheduled FTR target allocation and the FTR payout ratio. The self-scheduled FTR target allocation is equal to the product of the self-scheduled FTR MW and the congestion price differences between sink and source that occur in the Day-Ahead Energy Market. Over the entire PJM footprint, the FTR payout ratios were 91% for the 2005 to 2006 planning period and 100% for the 2006 to 2007 and the 2007 to 2008 (through December 31, 2007) planning periods. The total hedge is the sum of the ARR credits and the self-scheduled FTR credits. The Auction Related Total Energy Charges are the peak network load pro rata share of total load related energy charges in the Real-Time Energy Market for each control zone and planning period. The last column shows the percent of load related real time energy charges for the BGS auction offset by the ARRs and self-scheduled FTRs credits of the BGS auction.

For an example of zonal detail, Table 77 shows that the pro rata share of load attributable to the winners of load in the BGS auctions for the AECO Control Zone for the 2005 to 2006 planning period, requested 876.7 MW of ARRs, of which 805.4 MW cleared. Out of those 805.4 MW of cleared ARRs, 120.3 MW were self-scheduled as FTRs during the Annual FTR Auction. The total hedge of both ARR and self-scheduled FTR credits was approximately $14.1 million. The table shows that the total of ARR and self-scheduled FTR credits hedged about 3.6 percent of the approximately $397 million in auction related energy charges in the Real-Time Energy Market.

Table 77 ARR and self-scheduled FTR energy charge hedging by control zone for the BGS Auction: Planning periods 2005 to 2006, 2006 to 2007 and 2007 to 2008 through December 31, 2007

Control Zone	Planning Period	ARR Requested MW	ARR Cleared MW	ARR Credits	Self-Scheduled FTR MW	Self-Scheduled FTR Credits	Total Hedge	BGS related energy charges	Percent Hedged
AECO	2005/2006	876.7	805.4	$10,879,000	120.3	$3,277,439	$14,156,438	$397,100,938	3.6%
	2006/2007	788.8	764.4	$12,953,058	23.2	$868,487	$13,821,545	$251,678,116	5.5%
	2007/2008	939.1	738.9	$3,025,727	61.2	$768,352	$3,794,079	$179,925,568	2.1%
JCPL	2005/2006	2,054.9	946.0	$9,218,827	273.0	$5,370,411	$14,589,238	$752,486,219	1.9%
	2006/2007	2,404.5	1,069.7	$16,300,443	325.9	$4,386,502	$20,686,945	$638,516,446	3.2%
	2007/2008	2,072.9	1,123.6	$4,473,108	390.5	$5,183,452	$9,656,560	$433,319,839	2.2%
PSEG	2005/2006	4,758.4	2,888.4	$44,155,477	128.4	$3,744,458	$47,899,935	$1,793,735,039	2.7%
	2006/2007	3,788.1	2,166.0	$50,952,253	202.7	$5,246,663	$56,198,915	$1,271,883,704	4.4%
	2007/2008	3,042.1	2,115.5	$18,188,034	219.5	$3,976,708	$22,164,742	$901,143,223	2.5%
RECO	2005/2006	205.5	57.7	$612,073	0.8	$29,649	$641,722	$66,893,367	1.0%
	2006/2007	74.8	74.8	$439,159	0.0	$0	$439,159	$29,799,449	1.5%
	2007/2008	125.3	125.3	$208,380	0.0	$0	$208,380	$23,130,521	0.9%

Market Performance

Volume

Table 78 lists the annual ARR allocation volume by control zone, stage and round for the 2005 to 2006, the 2006 to 2007 and the 2007 to 2008 planning periods.

Table 78 Annual ARR allocation volume: Planning periods 2005 to 2006, 2006 to 2007 and 2007 to 2008

Planning Period	Control Zone	Stage	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2005/2006	AECO	Stage 1	48,612	1,577.0	1,412.3	89.6%	164.7	10.4%
		Stage 2	22,955	1,021.8	444.6	43.5%	577.2	56.5%
		Total	71,567	2,598.8	1,856.9	71.5%	741.9	28.5%
	JCPL	Stage 1	66,512	1,416.9	1,414.6	99.8%	2.3	0.2%
		Stage 2	50,828	3,854.1	915.7	23.8%	2,938.4	76.2%
		Total	117,340	5,271	2,330	44.2%	2,940.7	55.8%
	PSEG	Stage 1	237,921	5,384	4,485	83.3%	899.1	16.7%
		Stage 2	211,958	4,724	1,490	31.5%	3,234.3	68.5%
		Total	449,879	10,108	5,975	59.1%	4,133.4	40.9%
	RECO	Stage 1	0	0	0	NA	0.0	NA
		Stage 2	1,744	383	104	27.2%	279.0	72.8%
		Total	1,744	383	104	27.2%	279.0	72.8%
2006/2007	AECO	Stage 1	47,688	1,579	1,508	95.5%	71.1	4.5%
		Stage 2	20,372	1,317	732	55.5%	585.5	44.5%
		Total	68,060	2,897	2,240	77.3%	656.6	22.7%
	JCPL	Stage 1	64,012	1,422	1,422	100.0%	0.0	0.0%
		Stage 2	40,090	4,701	1,102	23.4%	3,599.7	76.6%
		Total	104,102	6,123	2,524	41.2%	3,599.7	58.8%
	PSEG	Stage 1	301,829	5,478	3,987	72.8%	1,491.2	27.2%
		Stage 2	111,382	6,721	1,068	15.9%	5,652.9	84.1%
		Total	413,211	12,199	5,055	41.4%	7,144.1	58.6%
	RECO	Stage 1	0	0	0	NA	0.0	NA
		Stage 2	1,008	416	246	59.2%	169.4	40.8%
		Total	1,008	416	246	59.2%	169.4	40.8%
2007/2008	AECO	Stage 1A	30,725	1,454	1,454	100.0%	0.0	0.0%
		Stage 1B	20,000	440	440	100.0%	0.0	0.0%
		Stage 2	17,677	1,363	365	26.7%	998.7	73.3%
		Total	68,402	3,257	2,258	69.3%	998.7	30.7%
	JCPL	Stage 1A	61,827	1,369	1,369	100.0%	0.0	0.0%
		Stage 1B	6,080	67	60	89.2%	7.2	10.8%
		Stage 2	51,110	5,160	1,636	31.7%	3,523.5	68.3%
		Total	119,017	6,596	3,065	46.5%	3,530.7	53.5%
	PSEG	Stage 1A	204,590	4,553	4,553	100.0%	0.0	0.0%
		Stage 1B	80,089	1,293	191	14.8%	1,101.6	85.2%
		Stage 2	152,968	6,342	321	5.1%	6,021.2	94.9%
		Total	437,647	12,188	5,066	41.6%	7,122.8	58.4%
	RECO	Stage 1A	0	0	0	NA	0.0	NA
		Stage 1B	0	0	0	NA	0.0	NA
		Stage 2	486	430	401	93.2%	29.3	6.8%
		Total	486	430	401	93.2%	29.3	6.8%