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 Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for the first three months of 2012, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM Energy Market results were competitive in the first three months of 2012.

Table 2-1 The Energy Market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Effective

- The aggregate market structure was evaluated as competitive because the calculations for hourly HHI (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market during the first three months of 2012 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1235 with a minimum of 1107 and a maximum of 1499 in the first three months of 2012.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in a number of local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for local market power, PJM's application of the three pivotal supplier test mitigated local market power and forced competitive offers, correcting for structural issues created by local transmission constraints.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself 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.[2] The approach to market power mitigation in PJM has 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 only 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.[3]

Highlights

- Average offered supply increased by 16,249, or 10.0 percent, from 157,340 MW in the first quarter of 2011 to 173,590 MW in the first quarter of 2012. The increase in offered supply was the result of the integration of the Duke Energy Ohio/Kentucky (DEOK) transmission zone in the first quarter of 2012, the integration of the American Transmission Systems, Inc. (ATSI) transmission zone in the second quarter of 2011, and the addition of 5,008 MW of nameplate capacity to PJM in 2011. The increases in supply were partially offset by the deactivation of three units (955 MW) since January 1, 2012.

1 Analysis of 2012 market results requires comparison to prior years. 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. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. 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 control zones, the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

2 OATT Attachment M

3 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.

- In January through March 2012, coal units provided 39.9 percent, nuclear units 36.3 percent and gas units 19.0 percent of total generation. Compared to January through March 2011, generation from coal units decreased 11.6 percent, generation from nuclear units increased 8.3 percent, while generation from natural gas units increased 66.0 percent, and generation from oil units increased 54.2 percent.
- The PJM system peak load for the first quarter of 2012 was 122,539 MW, which was 11,880 MW, or 10.7 percent, higher than the PJM peak load for the first quarter of 2011.[4] The ATSI and DEOK transmission zones accounted for 14,019 MW in the peak hour of the first quarter of 2012. The peak load excluding the ATSI and DEOK transmission zones was 108,519 MW, a decrease of 2,139 MW from the first quarter 2011 peak load.
- PJM average real-time load in the first quarter of 2012 increased by 6.4 percent from the first quarter of 2011, from 81,018 MW to 86,310 MW. The PJM average real-time load in the first quarter of 2012 would have decreased by 6.5 percent from the first quarter of 2011, from 81,018 MW to 75,753 MW, if the DEOK and ATSI transmission zones were excluded.
- PJM average day-ahead load, including DECs and up-to congestion transactions, increased in the first quarter of 2012 by 20.7 percent from the first quarter of 2011, from 107,116 MW to 129,258 MW. PJM average day-ahead load would have been 9.2 percent higher in the first quarter of 2012 than in the first quarter of 2011, from 107,116 MW to 116,964 MW if the DEOK and ATSI transmission zones were excluded.
- PJM average real-time generation increased by 5.5 percent in the first quarter of 2012 from the first quarter of 2011, from 83,505 MW to 88,068 MW. PJM average real-time generation would have decreased 5.1 percent in the first quarter of 2012 from the first quarter of 2011, from 83,505 MW to 79,276 MW if the DEOK and ATSI transmission zones were excluded.
- PJM Real-Time Energy Market prices decreased in the first quarter of 2012 compared to the first quarter of 2011. The load-weighted average LMP was 32.7 percent lower in the first quarter of 2012 than in the first quarter of 2011, $31.21 per MWh versus $46.35 per MWh.
- PJM Day-Ahead Energy Market prices decreased in the first quarter of 2012 compared to the first quarter of 2011. The load-weighted average LMP was 33.2 percent lower in the first quarter of 2012 than in the first quarter of 2011, $31.51 per MWh versus $47.14 per MWh.
- Levels of offer capping for local market power remained low. In the first three months of 2012, 1.9 percent of unit hours and 1.3 percent of MW were offer capped in the Real-Time Energy Market and 0.1 percent of unit hours and 0.2 percent of MW were offer capped in the Day-Ahead Energy Market.
- Of the 106 units that were eligible to include a Frequently Mitigated Unit (FMU) or Associated Unit (AU) adder in their cost-based offer during the first three months of 2012, 82 (77.4 percent) qualified in all months, and 12 (11.3 percent) qualified in only one month of 2012.
- There were no scarcity pricing events in the first three months of 2012 under PJM's current Emergency Action based scarcity pricing rules.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in the first three months of 2012, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand-side response programs, loads and prices in this section of the report.

Aggregate hourly supply offered increased by about 16,249 MW in the first quarter of 2012 compared to the first quarter of 2011, while aggregate peak load increased by 11,880 MW, modifying the general supply demand balance with a corresponding impact on Energy Market prices. In the Real-Time Market, average load in the first quarter of 2012 increased from the first quarter of 2011, from 81,018 MW to 86,310 MW. Market concentration levels remained moderate. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-

4 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2011 State of the Market Report for PJM*, Appendix I, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load. LMP is a broader indicator of the level of competition. While PJM has experienced price spikes, these have been limited in duration and, in general, prices in PJM have been well below the marginal cost of the highest cost unit installed on the system. The significant price spikes in PJM have been directly related to supply and demand fundamentals. In PJM, prices tend to increase as the market approaches scarcity conditions as a result of generator offers and the associated shape of the aggregate supply curve. The pattern of prices within days and across months and years illustrates how prices are directly related to demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price. Energy Market results for the first three months of 2012 generally reflected supply-demand fundamentals.

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 transmission constraints. 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 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 demonstrates that it is working successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.[5]

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Nonetheless, with a market design that includes a direct and explicit scarcity pricing revenue true up mechanism, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power. Any such market design modification should occur only after scarcity pricing for price signals has been implemented and sufficient experience has been gained to permit a well calibrated and gradual change in the mix of revenues.

The MMU concludes that the PJM Energy Market results were competitive in the first three months of 2012.

5 See the *2011 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

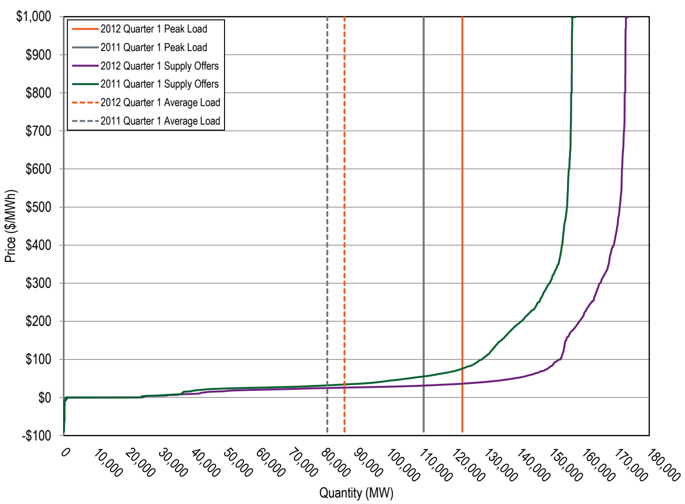
Market Structure

Supply

Average offered supply increased by 16,249, or 10.0 percent, from 157,340 MW in the first three months of 2011 to 173,590 MW in the first three months of 2012.[6] The large increase in offered supply was the result of the integration of the DEOK transmission zone in the first quarter of 2012, integration of the ATSI transmission zone in the second quarter of 2011, plus the addition of 5,008 MW of nameplate capacity to PJM in 2011. This includes five large plants (over 500 MW) that began generating in PJM in 2011. The increases in supply were partially offset by the deactivation of three units (955 MW) since January 1, 2012.

Figure 2-1 shows the average PJM aggregate supply curves, peak load and average load for the first quarter of 2011 and 2012.

Figure 2-1 Average PJM aggregate supply curves: January through March, 2011 and 2012 (See 2011 SOM, Figure 2-1)



6 Calculated values shown in Section 2, "Energy Market" are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

Energy Production by Fuel Source

Compared to January through March 2011, generation from coal units decreased 11.6 percent and generation from natural gas units increased 66.0 percent (Table 2-2). If the impact of the increased coal from the newly integrated ATSI and DEOK zones is eliminated, generation from coal units decreased 25.0 percent in the first quarter of 2012 compared to the first quarter of 2011.

Table 2-2 PJM generation (By fuel source (GWh)): January through March 2011 and 2012[7] (See 2011 SOM, Table 2-2)

	Jan-Mar 2011		Jan-Mar 2012		
	GWh	Percent	GWh	Percent	Change in Output
Coal	87,871.5	47.7%	77,677.8	39.9%	(11.6%)
Standard Coal	84,742.7	46.0%	75,121.6	38.6%	(10.9%)
Waste Coal	3,128.7	1.7%	2,556.2	1.3%	(0.7%)
Nuclear	65,194.7	35.4%	70,637.4	36.3%	8.3%
Gas	22,383.0	12.2%	37,024.4	19.0%	65.4%
Natural Gas	21,945.7	11.9%	36,430.7	18.7%	66.0%
Landfill Gas	437.3	0.2%	593.6	0.3%	35.7%
Biomass Gas	0.1	0.0%	0.1	0.0%	123.5%
Hydroelectric	3,647.6	2.0%	3,357.9	1.7%	(7.9%)
Wind	3,363.8	1.8%	4,261.3	2.2%	26.7%
Waste	1,359.1	0.7%	1,249.0	0.6%	(8.1%)
Solid Waste	1,034.0	0.6%	979.3	0.5%	(5.3%)
Miscellaneous	325.1	0.2%	269.7	0.1%	(17.1%)
Oil	229.3	0.1%	353.7	0.2%	54.2%
Heavy Oil	190.1	0.1%	315.3	0.2%	65.9%
Light Oil	35.4	0.0%	37.2	0.0%	5.2%
Diesel	2.4	0.0%	1.1	0.0%	(52.7%)
Kerosene	1.5	0.0%	0.2	0.0%	(88.4%)
Jet Oil	0.0	0.0%	0.0	0.0%	(26.4%)
Solar	7.0	0.0%	43.9	0.0%	526.8%
Battery	0.1	0.0%	0.1	0.0%	(40.5%)
Total	184,056.2	100.0%	194,605.6	100.0%	5.7%

7 Hydroelectric generation is total generation output and does not net out the MWh used at pumped storage facilities to pump water.

Table 2-3 PJM Generation (By fuel source (GWh)) excluding ATSI and DEOK zones: January through March 2011 and 2012 (See 2011 SOM, Table 2-2)

	Jan-Mar 2011		Jan-Mar 2012		
	GWh	Percent	GWh	Percent	Change in Output
Coal	87,871.5	47.7%	65,895.1	37.2%	(25.0%)
Standard Coal	84,742.7	46.0%	63,338.9	35.8%	(24.4%)
Waste Coal	3,128.7	1.7%	2,556.2	1.4%	(0.7%)
Nuclear	65,194.7	35.4%	66,012.3	37.3%	1.3%
Gas	22,383.0	12.2%	35,983.9	20.3%	60.8%
Natural Gas	21,945.7	11.9%	35,431.8	20.0%	61.5%
Landfill Gas	437.3	0.2%	552.0	0.3%	26.2%
Biomass Gas	0.1	0.0%	0.1	0.0%	123.5%
Hydroelectric	3,647.6	2.0%	3,357.9	1.9%	(7.9%)
Wind	3,363.8	1.8%	4,261.3	2.4%	26.7%
Waste	1,359.1	0.7%	1,249.0	0.7%	(8.1%)
Solid Waste	1,034.0	0.6%	979.3	0.6%	(5.3%)
Miscellaneous	325.1	0.2%	269.7	0.2%	(17.1%)
Oil	229.3	0.1%	352.9	0.2%	53.9%
Heavy Oil	190.1	0.1%	315.3	0.2%	65.9%
Light Oil	35.4	0.0%	37.1	0.0%	4.8%
Diesel	2.4	0.0%	0.4	0.0%	(82.8%)
Kerosene	1.5	0.0%	0.2	0.0%	(88.4%)
Jet Oil	0.0	0.0%	0.0	0.0%	(26.4%)
Solar	7.0	0.0%	43.9	0.0%	526.8%
Battery	0.1	0.0%	0.1	0.0%	(40.5%)
Total	184,056.2	100.0%	177,156.5	100.0%	(3.7%)

Generator Offers

Table 2-4 shows the distribution of MW generator offers by offer prices for the first quarter of 2012.

Table 2-4 Distribution[8] of MW for unit offer prices: January through March of 2012 (See 2011 SOM, Table 2-3)

	Range												
	($200) - $0		$0 - $200		$200 - $400		$400 - $600		$600 - $800		$800 - $1,000		
Unit Type	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Total
Battery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	100.0%
CC	0.0%	0.4%	62.2%	14.5%	13.3%	0.2%	1.4%	0.0%	6.7%	0.3%	1.0%	0.0%	100.0%
CT	0.0%	0.2%	37.0%	0.1%	19.2%	0.0%	9.1%	0.0%	29.1%	0.0%	5.1%	0.2%	100.0%
Diesel	0.0%	17.4%	10.2%	12.0%	49.3%	0.0%	8.7%	0.0%	1.4%	0.0%	0.9%	0.0%	100.0%
Hydrp	0.0%	96.6%	0.0%	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%	100.0%
Nuclear	0.0%	42.1%	9.2%	48.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Pumped Storage	53.5%	46.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Solar	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Steam	0.0%	1.4%	52.1%	22.1%	14.0%	9.9%	0.1%	0.0%	0.1%	0.2%	0.0%	0.1%	100.0%
Transaction	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	26.5%	67.2%	6.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
All Offers (by type)	1.6%	12.0%	40.1%	19.3%	12.0%	4.3%	2.2%	0.0%	7.1%	0.1%	1.3%	0.1%	100.0%
All Offers (total)		13.6%		59.4%		16.3%		2.2%		7.2%		1.4%	100.0%

Demand

The PJM system peak load for the first three months of 2012 was 122,539 MW in the HE 1900 on January 3, 2012, which was 11,880 MW, or 10.7 percent, higher than the PJM peak load for the first three months of 2011, which was 110,659 MW in the HE 800 on January 24, 2011. The ATSI and DEOK transmission zones accounted for 14,019 MW in the peak hour of the first quarter of 2012. The peak load excluding the ATSI and DEOK transmission zones was 108,519 MW, also occurring on January 3, 2012, HE 1900, a decrease of 2,139 MW from the first quarter 2011 peak load.

Table 2-5 shows the coincident first quarter peak loads for the years 2003 through 2012.

Table 2-5 Actual[9] PJM footprint peak loads: January through March of 2003 to 2012 (See 2011 SOM, Table 2-4)

(Jan - Mar)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
2003	Thu, January 23	19	54,670	NA	NA
2004	Mon, January 26	19	53,620	(1,050)	(1.9%)
2005	Tue, January 18	19	96,362	42,742	79.7%
2006	Mon, February 13	20	100,065	3,703	3.8%
2007	Mon, February 05	20	118,800	18,736	18.7%
2008	Thu, January 03	19	111,724	(7,076)	(6.0%)
2009	Fri, January 16	19	117,169	5,445	4.9%
2010	Mon, January 04	19	109,210	(7,959)	(6.8%)
2011	Mon, January 24	8	110,659	1,448	1.3%
2012 (with DEOK and ATSI)	Tue, January 03	19	122,539	11,880	10.7%
2012 (without DEOK and ATSI))	Tue, January 03	19	108,519	(2,139)	(1.9%)

8 Each range in the table is greater than the start value and less than or equal to the end value.

9 Peak loads shown are eMTR load. See the *MMU Technical Reference for the PJM Markets*, at "Load Definitions" for detailed definitions of load.

Figure 2-2 shows the first quarter peak loads for the years 2003 through 2012.

Figure 2-2 PJM[10] footprint first quarter peak loads: 2003 to 2012 (See 2011 SOM, Figure 2-2)

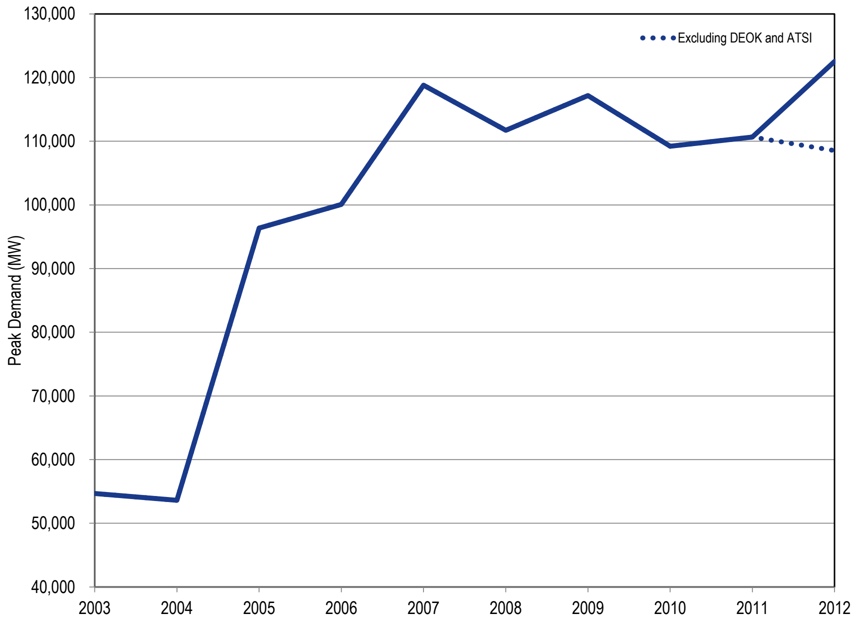
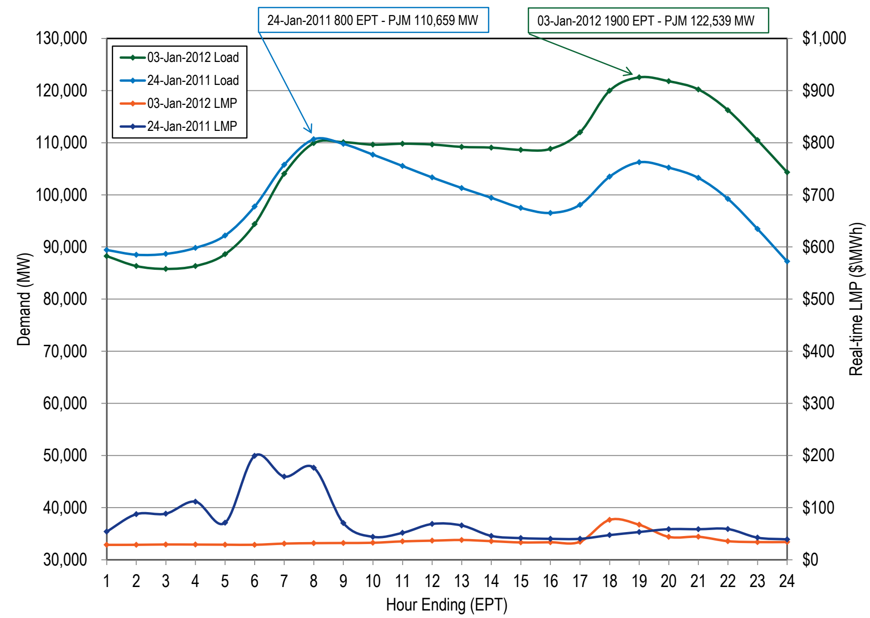


Figure 2-3 shows the peak load and LMP comparison for the first quarter of 2011 and 2012.

Figure 2-3 PJM peak-load comparison: Tuesday, January 03, 2012, and Monday, January 24, 2011 (See 2011 SOM, Figure 2-3)



Market Concentration

Analyses of supply curve segments of the PJM Energy Market for the first three months of 2012 indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.[11] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal during high demand periods. When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall Energy Market. PJM offer-capping rules that limit the exercise of local market

10 For additional information on the "PJM Integration Period", see the *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

11 For the market concentration analysis, supply curve segments are based on a classification of units that generally participate in the PJM Energy Market at varying load levels. Unit class is a primary factor for each classification; however, each unit may have different characteristics that influence the exact segment for which it is classified.

power and generation owners' obligations to serve load were generally effective in preventing the exercise of market power in these areas during the first three months of 2012. If those obligations were to change or the rules were to change, however, the market power related incentives and impacts would change as a result.

Hourly PJM Energy Market HHIs were calculated based on the real-time energy output of generators, adjusted for hourly net imports by owner (Table 2-6).

Hourly Energy Market HHIs by supply curve segment were calculated based on hourly Energy Market shares, unadjusted for imports.

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during the first three months of 2012 was moderately concentrated (Table 2-6).

Table 2-6 PJM hourly Energy Market HHI: January through March 2012[12] (See 2011 SOM, Table 2-5)

	Hourly Market HHI
Average	1235
Minimum	1107
Maximum	1499
Highest market share (One hour)	28%
Average of the highest hourly market share	22%
# Hours	2,183
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

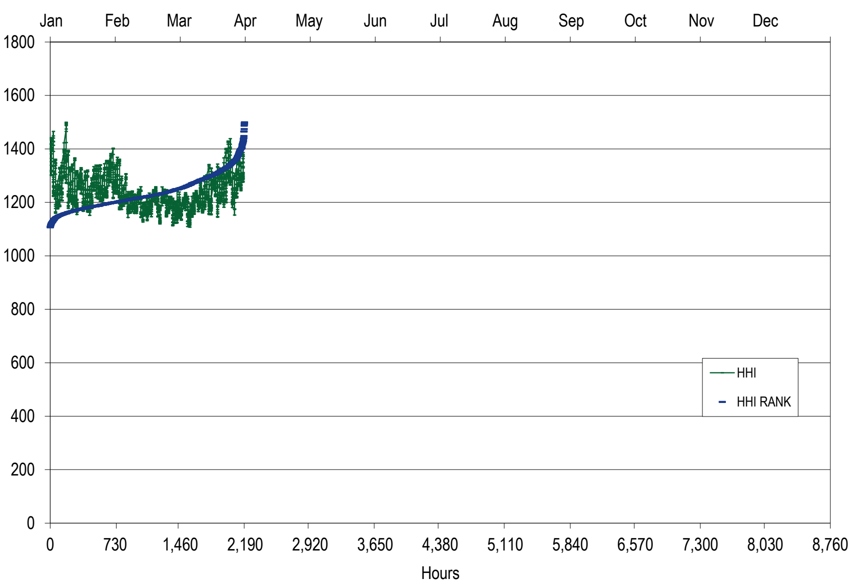
Table 2-7 includes 2012 HHI values by supply curve segment, including base, intermediate and peaking plants.

Table 2-7 PJM hourly Energy Market HHI (By supply segment): January through March 2012 (See 2011 SOM, Table 2-6)

	Minimum	Average	Maximum
Base	1110	1239	1496
Intermediate	1160	2916	7597
Peak	966	6682	10000

Figure 2-4 presents the 2012 hourly HHI values in chronological order and an HHI duration curve that shows 2012 HHI values in ascending order of magnitude.

Figure 2-4 PJM hourly Energy Market HHI: January through March 2012 (See 2011 SOM, Figure 2-4)



12 This analysis includes all hours in the first three months of 2012, regardless of congestion.

Local Market Structure and Offer Capping

In the PJM Energy Market, offer capping occurs only as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets. There are no explicit rules governing market structure or the exercise of market power in the aggregate Energy Market. PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power.

Levels of offer capping have historically been low in PJM, as shown in Table 2-8.

Table 2-8 Annual offer-capping statistics: 2008 through March 2012 (See 2011 SOM, Table 2-7)

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2008	1.0%	0.2%	0.2%	0.1%
2009	0.4%	0.1%	0.1%	0.0%
2010	1.2%	0.4%	0.2%	0.1%
2011	0.9%	0.4%	0.0%	0.0%
2012 (Jan - Mar)	1.9%	1.3%	0.1%	0.2%

Table 2-9 presents data on the frequency with which units were offer capped in the first three months of 2012.

Table 2-9 Real-time offer-capped unit statistics: January through March 2012 (See 2011 SOM, Table 2-8)

	2012 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	0	3	53
80% and < 90%	2	0	0	0	0	7
75% and < 80%	1	0	0	0	0	3
70% and < 75%	2	0	0	0	0	7
60% and < 70%	2	0	0	1	0	15
50% and < 60%	2	0	0	2	2	18
25% and < 50%	4	0	3	1	1	16
10% and < 25%	0	1	2	1	3	14

Table 2-9 shows that a small number of units are offer capped for a significant number of hours or for a significant proportion of their run hours.

Units that are offer capped for greater than, or equal to, 60 percent of their run hours are designated as frequently mitigated units (FMUs). An FMU or units that are associated with the FMU (AUs) are entitled to include adders in their cost-based offers that are a form of local scarcity pricing.

Local Market Structure

In the first three months of 2012, the AECO, AEP, AP, BGE, ComEd, DLCO, DPL, PENELEC, Pepco and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 25 or more hours. Actual competitive conditions in the Real-Time Energy Market associated with each of these frequently binding constraints were analyzed using the three pivotal supplier results for the first three months of 2012.[13] The DAY, Dominion, JCPL, Met-Ed, PECO, PPL and RECO Control Zones were not affected by constraints binding for 25 or more hours.

The MMU analyzed the results of the three pivotal supplier tests conducted by PJM for the Real-Time Energy Market for the period January 1, 2012, through March 31, 2012. The three pivotal supplier test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. Only uncommitted resources, which would be started to relieve the transmission constraint, are subject to offer capping. Already committed units that can provide incremental relief cannot be offer capped. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Table 2-10 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners.

13 See the *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test.

Table 2-10 Three pivotal supplier results summary for regional constraints: January through March 2012 (See 2011 SOM, Table 2-9)

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
5004/5005 Interface	Peak	1,198	342	29%	1,028	86%
	Off Peak	560	272	49%	410	73%
AEP-DOM	Peak	257	10	4%	251	98%
	Off Peak	415	20	5%	409	99%
AP South	Peak	994	124	12%	957	96%
	Off Peak	937	236	25%	868	93%
Bedington - Black Oak	Peak	7	1	14%	7	100%
	Off Peak	NA	NA	NA	NA	NA
Central	Peak	27	6	22%	26	96%
	Off Peak	NA	NA	NA	NA	NA
Eastern	Peak	160	69	43%	107	67%
	Off Peak	NA	NA	NA	NA	NA
Western	Peak	36	29	81%	16	44%
	Off Peak	9	6	67%	5	56%

Table 2-11 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing for the regional 500 kV constraints.

Table 2-11 Three pivotal supplier test details for regional constraints: January through March 2012 (See 2011 SOM, Table 2-10)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	344	548	17	4	13
	Off Peak	212	406	16	7	9
AEP-DOM	Peak	226	280	8	0	7
	Off Peak	220	362	9	0	8
AP South	Peak	293	487	10	1	9
	Off Peak	257	523	11	2	9
Bedington - Black Oak	Peak	214	225	16	3	13
	Off Peak	NA	NA	NA	NA	NA
Central	Peak	347	451	15	2	13
	Off Peak	NA	NA	NA	NA	NA
Eastern	Peak	426	656	15	8	7
	Off Peak	NA	NA	NA	NA	NA
Western	Peak	449	966	19	14	5
	Off Peak	227	551	14	8	6

Table 2-12 provides, for the identified seven regional constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping uncommitted units.

Table 2-12 Summary of three pivotal supplier tests applied for regional constraints: January through March 2012 (See 2011 SOM, Table 2-11)

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
5004/5005 Interface	Peak	1,198	21	2%	13	1%	62%
	Off Peak	560	3	1%	0	0%	0%
AEP-DOM	Peak	257	2	1%	1	0%	50%
	Off Peak	415	14	3%	12	3%	86%
AP South	Peak	994	13	1%	3	0%	23%
	Off Peak	937	8	1%	0	0%	0%
Bedington - Black Oak	Peak	7	1	14%	1	14%	100%
	Off Peak	NA	NA	NA	NA	NA	NA
Central	Peak	27	0	0%	0	0%	0%
	Off Peak	NA	NA	NA	NA	NA	NA
Eastern	Peak	160	9	6%	4	3%	44%
	Off Peak	NA	NA	NA	NA	NA	NA
Western	Peak	36	0	0%	0	0%	0%
	Off Peak	9	0	0%	0	0%	0%

Frequently Mitigated Unit and Associated Unit Adders

An FMU is a frequently mitigated unit. FMUs were first provided additional compensation as a form of scarcity pricing in 2005.[14] The definition of FMUs provides for a set of graduated adders associated with increasing levels of offer capping. 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.[15] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.[16,17]

An AU, or associated unit, is a unit that is physically, electrically and economically identical to an FMU, but does not qualify for the same FMU adder. 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. The AU designation was implemented 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.

FMUs and AUs are designated monthly, where a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[18]

Table 2-13 shows the number of FMUs and AUs in the first three months of 2012. For example, in March 2012, there were 25 FMUs and AUs in Tier 1, 17 FMUs and AUs in Tier 2, and 47 FMUs and AUs in Tier 3.

Table 2-13 Number of frequently mitigated units and associated units (By month): January through March, 2012 (See 2011 SOM, Table 2-26)

	FMUs and AUs			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	26	21	52	99
February	26	22	47	95
March	25	17	47	89

Figure 2-5 shows the total number of FMUs and AUs that qualified for an adder since the inception of the business rule in February, 2006.

14 110 FERC ¶ 61,053 (2005).
15 OA, Schedule 1 § 6.4.2.
16 114 FERC ¶ 61, 076 (2006).
17 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).
18 OA, Schedule 1 § 6.4.2. In 2007, the FERC approved OA revisions to clarify the AU criteria.

Figure 2-5 Frequently mitigated units and associated units (By month): February, 2006 through March, 2012 (See 2011 SOM, Figure 2-5)

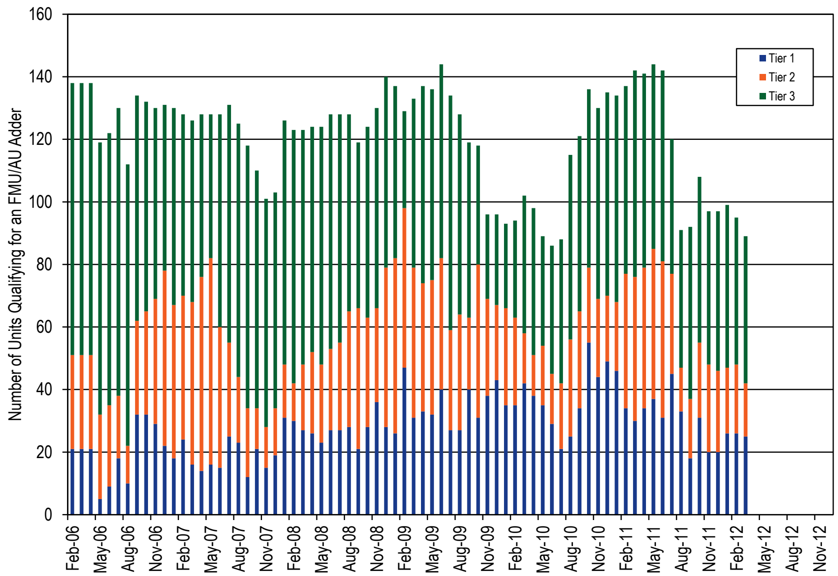


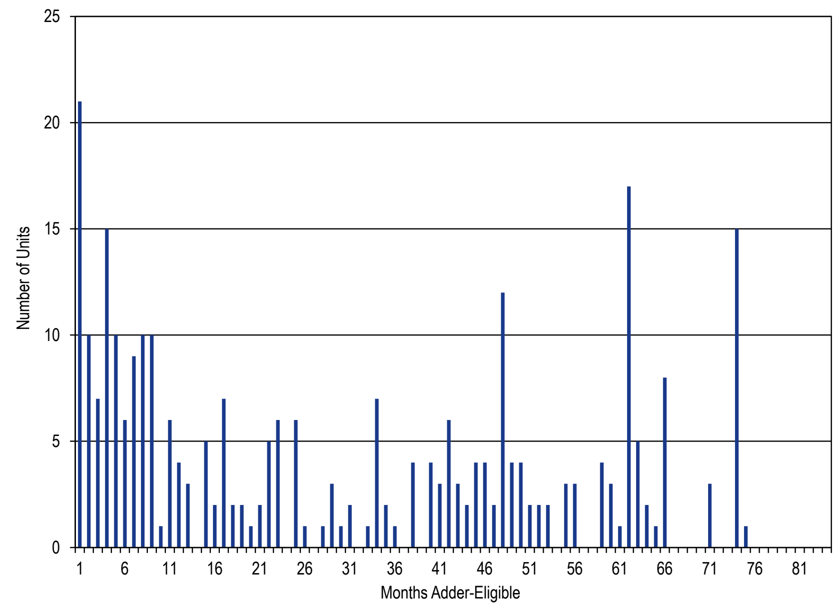
Table 2-14 shows the number of months FMUs and AUs were eligible for any adder (Tier 1, Tier 2 or Tier 3) during the first three months 2012. Of the 106 units eligible in at least one month during the first three months of 2012, 82 units (77.4 percent) were FMUs or AUs for all three months.

Table 2-14 Frequently mitigated units and associated units total months eligible: January through March, 2012 (See 2011 SOM, Table 2-27)

Months Adder-Eligible	FMU & AU Count
1	12
2	12
3	82
Total	106

Figure 2-6 shows the number of months FMUs and AUs were eligible for any adder (Tier 1, Tier 2 or Tier 3) since the inception of FMUs effective February 1, 2006. From February 1, 2006, through March 31, 2012, there have been 293 unique units that have qualified for an FMU adder in at least one month. Of these 293 units, only one unit qualified for an adder in all potential months. Fifteen additional units qualified in 74 of the 75 possible months, and 124 of the 293 units (42.3 percent) have qualified for an adder in more than half of the possible months.

Figure 2-6 Frequently mitigated units and associated units total months eligible: February, 2006 through March, 2012 (See 2011 SOM, Figure 2-6)



Market Performance: Load and LMP

The PJM system load and LMP reflect the configuration of the entire RTO. The PJM Energy Market includes the Real-Time Energy Market and the Day-Ahead Energy Market.

Load

PJM average real-time load in the first quarter of 2012 increased by 6.5 percent from the first quarter of 2011, from 81,018 MW to 86,310 MW. The PJM average real-time load in the first quarter of 2012 would have decreased by 6.5 percent from the first quarter of 2011, from 81,018 MW to 75,753 MW, if the DEOK and ATSI transmission zones were excluded.

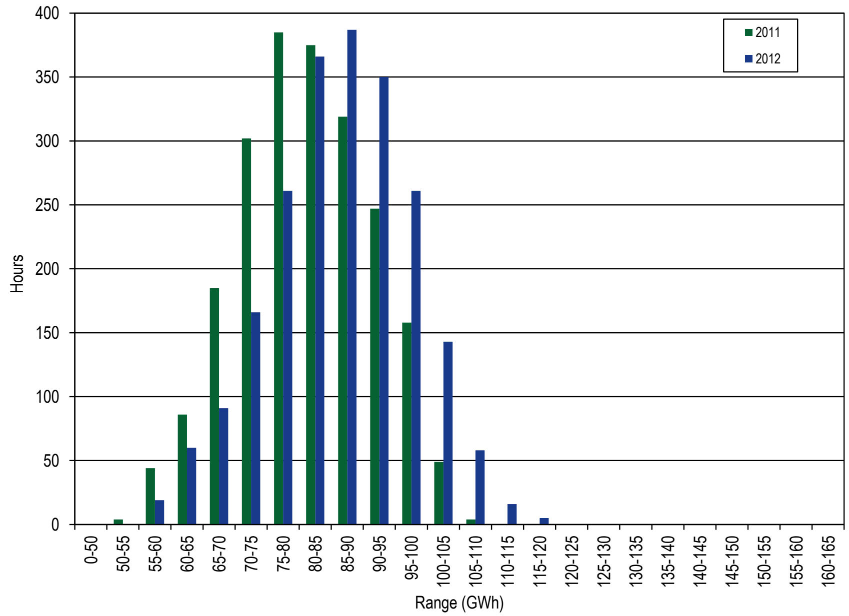
PJM average day-ahead load in the first quarter of 2012, including DECs and up-to congestion transactions, increased by 20.7 percent from the first quarter of 2011, from 107,116 MW to 129,258 MW. PJM average day-ahead load in the first quarter of 2012, including DECs and up-to congestion transactions, would have been 9.2 percent higher than in the first quarter of 2011, from 107,116 MW to 116,964 MW if the DEOK and ATSI transmission zones were excluded.

Real-Time Load

PJM Real-Time Load Duration

Figure 2-7 shows the hourly distribution of PJM real time load for the first quarter of 2011 and 2012.[19]

Figure 2-7 PJM real-time accounting load histogram: January through March for years 2011 and 2012[20] (See 2011 SOM, Figure 2-7)



PJM Real-Time, Average Load

Table 2-15 presents summary real-time load statistics for the first quarter for the 15 year period 1998 to 2012. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through marginal loss pricing.[21]

19 All real-time load data in Section 2, "Energy Market," "Market Performance: Load and LMP" are based on PJM accounting load. See the *Technical Reference for PJM Markets*, Section 5, "Load Definitions," for detailed definitions of accounting load.

20 Each range on the vertical axis includes the start value and excludes the end value.

21 Accounting load is used here because *PJM uses accounting load in the settlement process, which determines how much load customers pay for. In addition, the use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP, which excludes losses prior to June 1 and includes losses after June 1.*

Table 2-15 PJM real-time average hourly load: January through March for years 1998 through 2012 (See 2011 SOM, Table 2-28)

	PJM Real-Time Load (MWh)		Year-to-Year Change	
(Jan-Mar)	Average Load	Load Standard Deviation	Average Load	Load Standard Deviation
1998	28,019	3,762	NA	NA
1999	29,784	4,027	6.3%	7.0%
2000	30,367	4,624	2.0%	14.8%
2001	31,254	3,846	2.9%	(16.8%)
2002	29,968	4,083	(4.1%)	6.1%
2003	39,249	5,546	31.0%	35.8%
2004	39,549	5,761	0.8%	3.9%
2005	71,388	8,966	80.5%	55.6%
2006	80,179	8,977	12.3%	0.1%
2007	84,586	12,040	5.5%	34.1%
2008	82,235	10,184	(2.8%)	(15.4%)
2009	81,170	11,718	(1.3%)	15.1%
2010	81,121	10,694	(0.1%)	(8.7%)
2011	81,018	27,028	(0.1%)	152.7%
2012	86,310	28,501	6.5%	5.5%

PJM Real-Time, Monthly Average Load

Figure 2-8 compares the real-time, monthly average hourly loads in the first quarter of 2012 with those in 2011.

Figure 2-8 PJM real-time monthly average hourly load: 2011 through March of 2012 (See 2011 SOM, Figure 2-8)

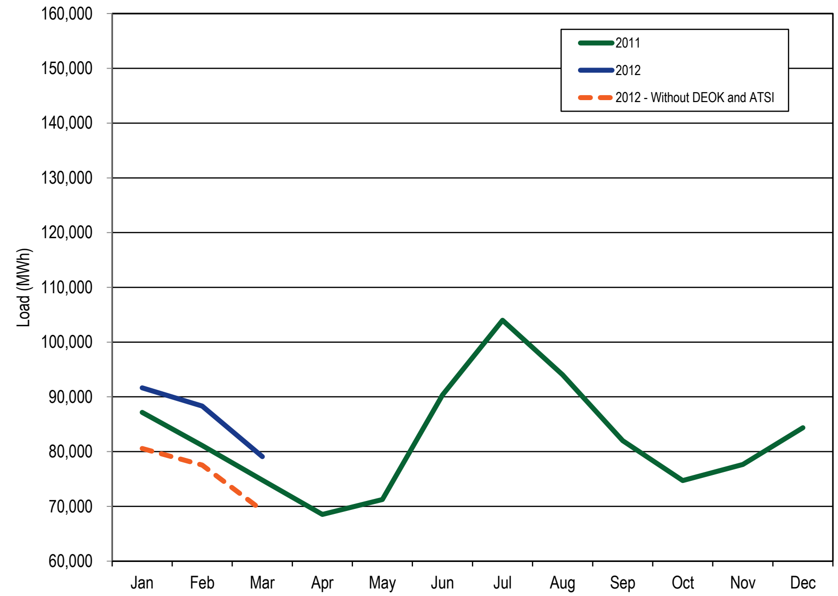


Table 2-16 shows the load weighted THI, WWP and average temperature for heating, cooling and shoulder seasons.[22]

22 The Summer THI is calculated by taking average of daily maximum THI in June, July and August. The Winter WWP is calculated by taking average of daily minimum WWP in January, February and December. Average temperature is used for the rest of months. For additional information on the calculation of these weather variables, see PJM "Manual 19: Load Forecasting and Analysis," Revision 18 (November 16, 2011), Section 3, pp. 15-16. Load weighting using real-time zonal accounting load.

Table 2-16 PJM annual Summer THI, Winter WWP and average temperature (Degrees F): cooling, heating and shoulder months of 2007 through 2012 (See 2011 SOM, Table 2-30)

	Summer THI	Winter WWP	Shoulder Average Temperature
2007	75.45	27.10	56.55
2008	75.35	27.52	54.10
2009	74.23	25.56	55.09
2010	77.36	24.28	57.22
2011	76.68	25.20	57.21
2012	NA	30.28	53.19

Day-Ahead Load

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

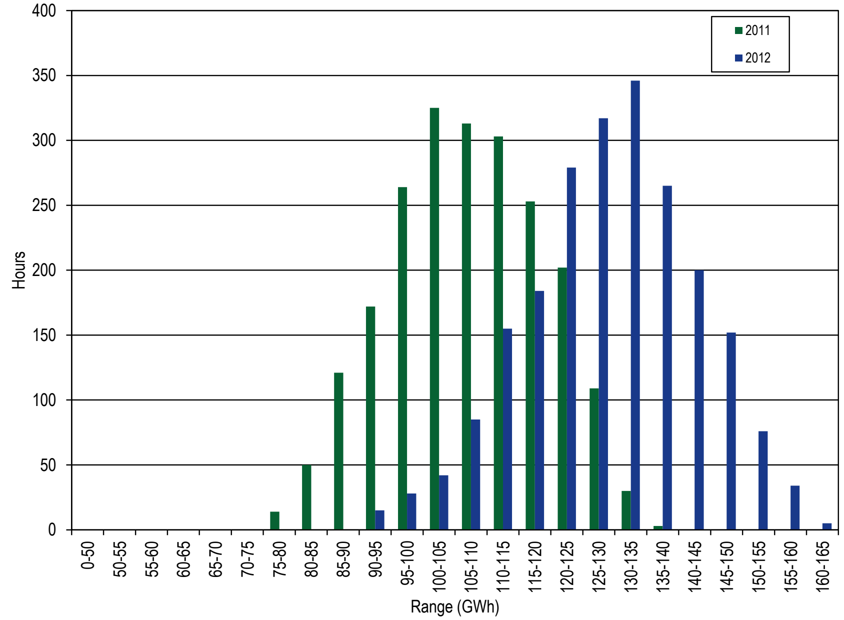
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of 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.
- **Up-to Congestion Transactions.** An up-to congestion transaction is a conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink.[23] In the PJM Day-Ahead Market, an up-to congestion transaction is evaluated and clears as a matched pair of injections and withdrawals analogous to a matched pair of INC offers and DEC bids. The DEC (sink) portion of each up-to congestion transaction is load in the Day-Ahead Energy Market. The INC (source) of each up-to congestion transaction is generation in the Day-Ahead Energy Market.

PJM day-ahead load is the hourly total of the four types of cleared demand bids.[24]

PJM Day-Ahead Load Duration

Figure 2-9 shows the hourly distribution of PJM day-ahead load for the first quarter of 2011 and 2012.

Figure 2-9 PJM day-ahead load histogram: January through March for years 2011 and 2012 (See 2011 SOM, Figure 2-9)



PJM Day-Ahead, Average Load

Table 2-17 presents summary day-ahead load statistics for the first quarter of 12 year period 2001 to 2012.

23 Up-to congestion transactions are cleared based on the entire price difference between source and sink including the congestion and loss components of LMP.

24 Since an up-to congestion transaction is treated as analogous to a matched pair of INC offers and DEC bids, the DEC portion of the up-to congestion transaction contributes to the PJM day-ahead load, and the INC portion contributes to the PJM day-ahead generation.

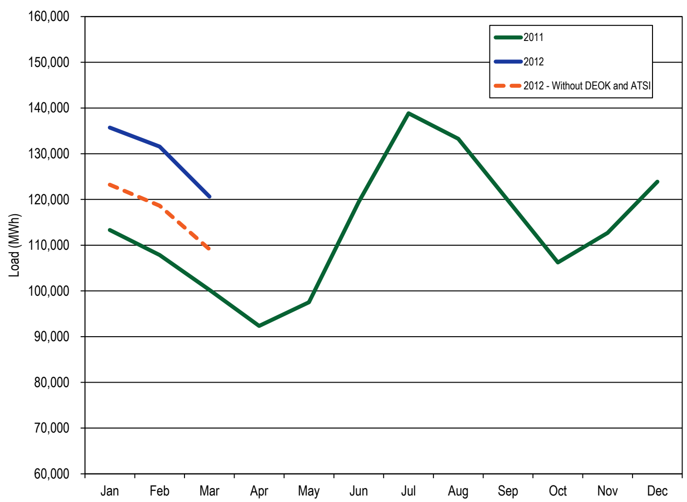
Table 2-17 PJM day-ahead average load: January through March for years 2001 through 2012 (See 2011 SOM, Table 2-31)

	PJM Day-Ahead Load (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
(Jan-Mar)	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load
2001	33,731	0	33,731	4,557	5	4,557	NA	NA	NA
2002	33,938	37	33,975	4,944	118	4,960	0.6%	11,350.0%	0.7%
2003	46,743	292	47,034	6,848	319	6,841	37.7%	686.0%	38.4%
2004	46,259	627	46,885	5,624	412	5,591	(1.0%)	114.8%	(0.3%)
2005	86,248	1,093	87,341	9,915	710	9,810	86.4%	74.5%	86.3%
2006	93,295	2,949	96,244	9,377	1,419	9,453	8.2%	169.7%	10.2%
2007	104,033	4,666	108,699	12,140	1,464	12,601	11.5%	58.3%	12.9%
2008	100,046	5,949	105,995	10,421	1,464	10,677	(3.8%)	27.5%	(2.5%)
2009	94,583	7,783	102,366	12,828	1,784	13,619	(5.5%)	30.8%	(3.4%)
2010	93,559	7,453	101,012	11,907	2,276	11,937	(1.1%)	(4.2%)	(1.3%)
2011	89,478	17,638	107,116	28,996	7,875	30,898	(4.4%)	136.7%	6.0%
2012	92,415	36,844	129,258	29,634	12,214	34,665	3.3%	108.9%	20.7%

PJM Day-Ahead, Monthly Average Load

Figure 2-10 compares the day-ahead, monthly average hourly loads of the first quarter of 2012 with those of 2011.

Figure 2-10 PJM day-ahead monthly average hourly load: 2011 through March of 2012 (See 2011 SOM, Figure 2-10)



Real-Time and Day-Ahead Load

Table 2-18 presents summary statistics for the first quarter of 2011 and 2012 day-ahead and real-time loads.

Table 2-18 Cleared day-ahead and real-time load (MWh): January through March for years 2011 and 2012 (See 2011 SOM, Table 2-32)

		Day Ahead					Real Time	Average Difference	
	(Jan-Mar)	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bids	Cleared Up-to Congestion	Total Load	Total Load	Total Load	Total Load Minus Cleared DEC Bids Minus Up-to Congestion
Average	2011	77,744	859	10,875	17,638	107,116	81,018	26,097	(2,415)
	2012	83,557	895	7,962	36,844	129,258	86,310	42,949	(1,857)
Median	2011	77,437	852	10,734	17,496	107,132	80,991	26,141	(2,089)
	2012	84,076	886	7,852	36,671	129,802	86,486	43,316	(1,207)
Standard Deviation	2011	9,641	189	1,894	2,654	11,890	10,273	1,617	(2,931)
	2012	10297	135	1584	4088	13163	10947	2,216	(3,457)
Peak Average	2011	83,588	950	11,877	18,130	114,546	87,187	27,359	(2,648)
	2012	90,231	963	8,501	37,274	136,970	92,965	44,005	(1,770)
Peak Median	2011	83,266	951	11,793	18,070	114,677	86,883	27,794	(2,069)
	2012	89,908	952	8,256	37,204	136,171	92,368	43,803	(1,657)
Peak Standard Deviation	2011	7,314	176	1,603	2,579	8,771	7,700	1,071	(3,111)
	2012	6764	120	1377	3967	9296	7549	1,747	(3,597)
Off-Peak Average	2011	72,472	777	9,970	17,193	100,412	75,453	24,959	(2,204)
	2012	77,485	833	7,471	36,452	122,242	80,255	41,987	(1,936)
Off-Peak Median	2011	72,228	772	9,769	17,020	99,884	74,949	24,935	(1,854)
	2012	77,190	830	7,276	36,179	122,389	79,600	42,789	(666)
Off-Peak Standard Deviation	2011	8,365	161	1,668	2,643	10,236	9,055	1,182	(3,130)
	2012	9,138	117	1,602	4,159	12,207	10,005	2,202	(3,559)

Figure 2-11 shows the first quarter average 2012 hourly cleared volume of fixed-demand bids, the sum of cleared fixed-demand and cleared price-sensitive bids, total day-ahead load and real-time load. The difference between the cleared fixed-demand and cleared price-sensitive bids and the total day-ahead load is cleared decrement bids and up-to congestion transactions.

Figure 2-11 Day-ahead and real-time loads (Average hourly volumes): January through March of 2012 (See 2011 SOM, Figure 2-10)

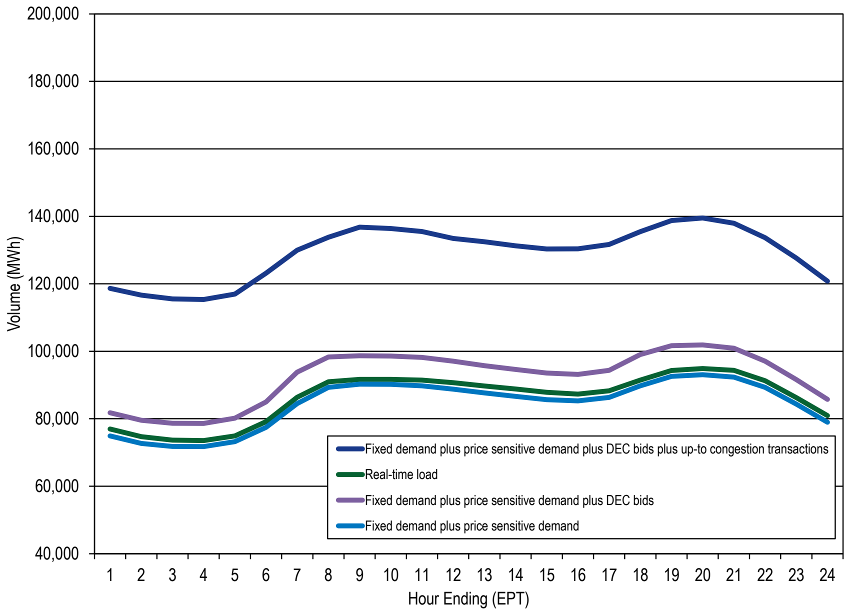


Figure 2-12 Difference between day-ahead and real-time loads (Average daily volumes): January 2011 through March 2012 (See 2011 SOM, Figure 2-12)

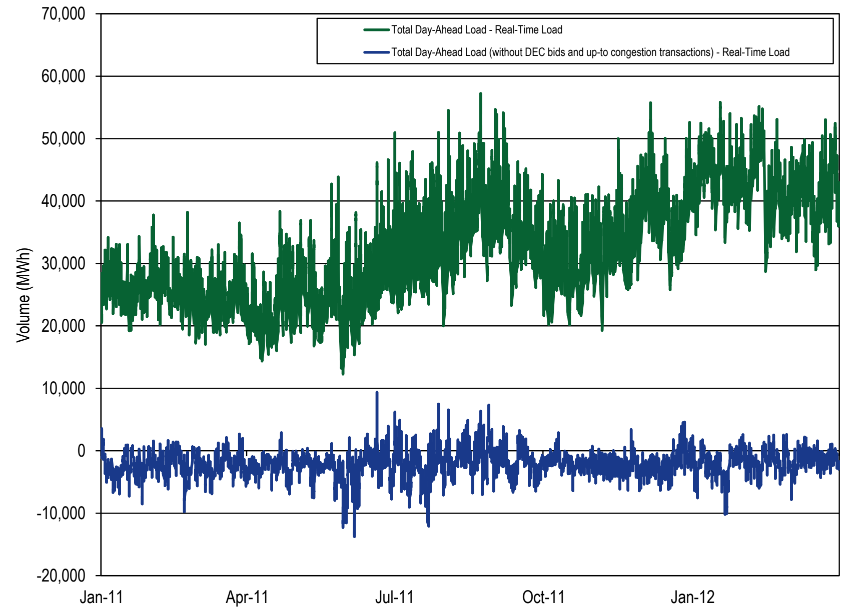


Figure 2-12 shows the difference between the day-ahead and real-time average daily loads in the first quarter of 2012 and the first quarter of 2011.

Real-Time and Day-Ahead Generation

PJM average real-time generation in the first quarter of 2012 increased by 5.5 percent from the first quarter of 2011, from 83,505 MW to 88,068 MW. PJM average real-time generation in the first quarter of 2012 would have decreased 5.1 percent from the first quarter of 2011, from 83,505 MW to 79,276 MW if the DEOK and ATSI transmission zones were excluded.

PJM average day-ahead generation in the first quarter of 2012, including INCs and up-to congestion transactions, increased by 19.8 percent from the first quarter of 2011, from 110,310 MW to 132,178 MW. PJM average day-ahead generation in the first quarter of 2012, including INCs and up-to congestion transactions, would have been 13.1 percent higher than in the first quarter of

2011, from 110,310 MW to 124,710 MW if the DEOK and ATSI transmission zones were excluded.

Real-time generation is the actual production of electricity during the operating day. Real-time generation will always be greater than real-time load because of system losses.

In the Day-Ahead Energy Market, four types of financially binding generation offers are made and cleared:[25]

- **Self-Scheduled.** Offer to supply a fixed block of MWh that must run from a specific unit, or as a minimum amount of MWh that must run from a specific unit that also has a dispatchable component above the minimum.[26]
- **Generator Offer.** Offer to supply a schedule of MWh from a specific unit and the corresponding offer prices.
- **Increment Offer (INC).** Financial offer to supply specified MWh at corresponding offer prices. An increment offer is a financial offer that can be submitted by any market participant.
- **Up-to Congestion Transactions.** An up-to congestion transaction is a conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink.[27] In the PJM Day-Ahead Market, an up-to congestion transaction is evaluated and clears as a matched pair of injections and withdrawals analogous to a matched pair of INC offers and DEC bids. The DEC (sink) portion of each up-to congestion transaction is load in the Day-Ahead Energy Market. The INC (source) of each up-to congestion transaction is generation in the Day-Ahead Energy Market.

Table 2-19 presents summary real-time generation statistics for the first quarter of the 10 year period from 2003 through 2012.

25 All references to day-ahead generation and increment offers are presented in cleared MWh in the "Real-Time and Day-Ahead Generation" portion of the *2011 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market."
26 The definition of self-scheduled is based on the PJM. "eMKT User Guide" (December 1, 2011), pp. 38-40.
27 Up-to congestion transactions are cleared based on the entire price difference between source and sink including the congestion and loss components of LMP.

Table 2-19 PJM real-time average hourly generation: January through March for years 2003 through 2012 (See 2011 SOM, Table 2-33)

	PJM Real-Time Generation (MWh)		Year-to-Year Change	
(Jan-Mar)	Average Generation	Generation Standard Deviation	Average Generation	Generation Standard Deviation
2003	38,731	5,187	NA	NA
2004	37,790	4,660	(2.4%)	(10.2%)
2005	74,187	8,269	96.3%	77.4%
2006	82,550	7,921	11.3%	(4.2%)
2007	86,286	10,018	4.5%	26.5%
2008	86,690	9,375	0.5%	(6.4%)
2009	81,987	11,417	(5.4%)	21.8%
2010	81,676	12,801	(0.4%)	12.1%
2011	83,505	26,470	2.2%	106.8%
2012	88,068	29,677	5.5%	12.1%

Table 2-20 presents summary day-ahead generation statistics for the first quarter of the 10 year period from 2003 to 2012.

Table 2-20 PJM day-ahead average hourly generation: January through March for years 2003 through 2012 (See 2011 SOM, Table 2-34)

	PJM Day-Ahead Generation (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
Year	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation
2003	36,855	292	37,147	4,379	319	4,337	NA	NA	NA
2004	45,964	627	46,591	4,825	412	4,794	24.7%	114.8%	25.4%
2005	87,918	1,093	89,011	9,529	710	9,434	91.3%	74.5%	91.0%
2006	94,370	2,949	97,319	8,974	1,419	9,035	7.3%	169.7%	9.3%
2007	105,433	4,666	110,099	11,438	1,464	11,938	11.7%	58.3%	13.1%
2008	103,763	5,949	109,711	10,197	1,464	10,479	(1.6%)	27.5%	(0.4%)
2009	97,097	7,783	104,880	13,093	1,784	13,895	(6.4%)	30.8%	(4.4%)
2010	94,280	7,453	101,733	14,264	2,276	13,835	(2.9%)	(4.2%)	(3.0%)
2011	92,672	17,638	110,310	29,591	7,875	31,507	(1.7%)	136.7%	8.4%
2012	95,334	36,844	132,178	31,303	12,214	36,348	2.9%	108.9%	19.8%

Table 2-21 presents summary statistics for first quarter of 2011 and 2012 for day-ahead and real-time generation.

Table 2-21 Day-ahead and real-time generation (MWh): January through March for years 2011 and 2012 (See 2011 SOM, Table 2-35)

		Day Ahead				Real Time	Average Difference	
	(Jan-Mar)	Cleared Generation	Cleared INC Offers	Cleared Up-to Congestion	Cleared Generation Plus INC Offers Plus Up-to Congestion	Generation	Cleared Generation	Cleared Generation Plus INC Offers Plus Up-to Congestion
Average	2011	84,725	7,947	17,638	110,310	83,505	1,220	26,805
	2012	88,942	6,392	36,844	132,178	88,068	874	44,110
Median	2011	85,010	7,844	17,496	110,435	83,643	1,367	26,792
	2012	89,373	6,345	36,671	132,597	88,079	1,294	44,518
Standard Deviation	2011	10,911	1,134	2,654	12,200	10,116	795	2,084
	2012	11,883	773	4,088	13,701	11,177	706	2,524
Peak Average	2011	91,389	8,554	18,130	118,073	89,689	1,700	28,384
	2012	96,169	6,557	37,274	140,000	94,441	1,728	45,559
Peak Median	2011	91,319	8,412	18,070	118,178	89,381	1,938	28,797
	2012	95,687	6,497	37,204	139,084	94,019	1,668	45,065
Peak Standard Deviation	2011	7,869	1,037	2,579	8,910	7,530	339	1,380
	2012	7,975	595	3,967	9,825	8,066	-90	1,759
Off-Peak Average	2011	78,713	7,400	17,193	103,306	77,925	788	25,381
	2012	82,367	6,242	36,452	125,061	82,271	96	42,790
Off-Peak Median	2011	78,214	7,398	17,020	102,905	77,614	600	25,291
	2012	82,252	6,106	36,179	125,297	82,113	139	43,184
Off-Peak Standard Deviation	2011	9,717	920	2,643	10,397	8,825	892	1,572
	2012	11,006	879	4,159	12,823	10,435	571	2,388

Figure 2-13 shows the first quarter average 2012 hourly cleared volumes of day-ahead generation without increment offers or up-to congestion transactions, the day-ahead generation including cleared increment bids and up-to congestion transactions and the real-time generation.[28]

Figure 2-13 Day-ahead and real-time generation (Average hourly volumes): January through March of 2012 (See 2011 SOM, Figure 2-13)

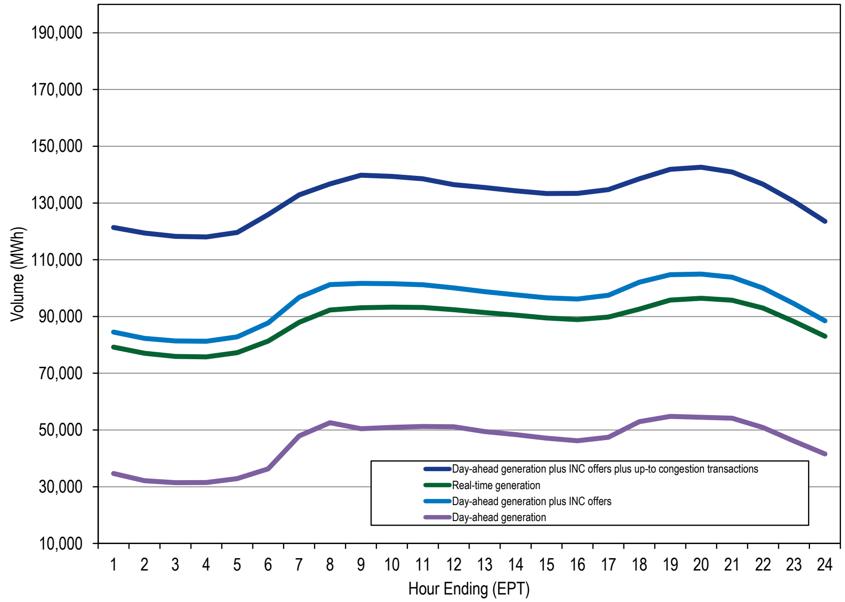
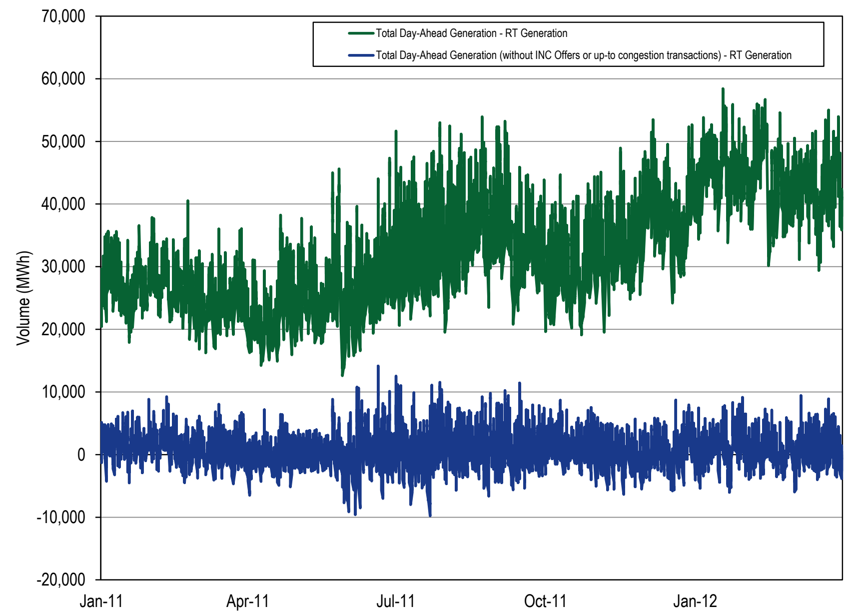


Figure 2-14 shows the difference between the day-ahead and real-time average daily generation in the first quarter of 2012 and the first quarter of 2011.

28 Generation data are the sum of MWh at every generation bus in PJM with positive output.

Figure 2-14 Difference between day-ahead and real-time generation (Average daily volumes): January 2011 through March 2012 (See 2011 SOM, Figure 2-14)



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.[29]

PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. Among other things, overall average prices reflect the changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses

29 See the *2011 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market," for methodological background, detailed price data and the *Technical Reference for PJM Markets*, Section 4, "Calculating Locational Marginal Price" for more information on how bus LMPs are aggregated to system LMPs.

and local price differences caused by congestion. Real-Time and Day-Ahead Energy Market load-weighted prices were 32.1 percent and 30.1 percent lower than in the first quarter of 2011 due to the decrease in gas prices coupled with warmer more stable winter weather.

PJM Real-Time Energy Market prices decreased in the first three months of 2012 compared to the first three months of 2011. The system average LMP was 32.1 percent lower in the first three months of 2012 than in the first three months of 2011, $30.38 per MWh versus $44.76 per MWh. The load-weighted average LMP was 32.7 percent lower in the first three months of 2012 than in the first three months of 2011, $31.21 per MWh versus $46.35 per MWh.

PJM Day-Ahead Energy Market prices decreased in the first three months of 2012 compared to the first three months of 2011. The system average LMP was 30.1 percent lower in the first three months of 2012 than in the first three months of 2011, $31.86 per MWh versus $45.60 per MWh. The load-weighted average LMP was 33.2 percent lower in the first three months of 2012 than in the first three months of 2011, $31.51 per MWh versus $47.14 per MWh.[30]

Real-Time LMP

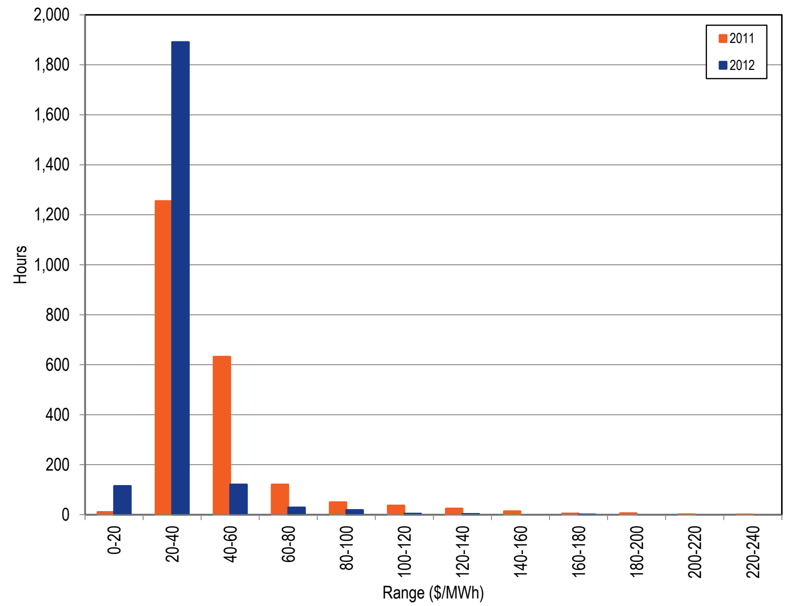
Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[31] This section discusses the real-time average LMP and the real-time load weighted average LMP. Average LMP is the simple, unweighted average LMP.

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 2-15 shows the number of hours that PJM real-time average LMP for the first quarter of 2011 and 2012 were within a defined range.

Figure 2-15 Average LMP histogram for the PJM Real-Time Energy Market: January through March, 2011 and 2012 (See 2011 SOM, Figure 2-15)



30 Tables reporting zonal and jurisdictional load and prices are in Appendix C. See the *2011 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market".

31 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for detailed definition of Real-Time LMP.

PJM Real-Time, Average LMP

Table 2-22 shows the PJM real-time, annual, average LMP for the first quarter of the 15-year period 1998 to 2012.[32]

Table 2-22 PJM real-time, average LMP (Dollars per MWh): January through March, 1998 through 2012 (See 2011 SOM, Table 2-36)

	Real-Time LMP			Year-to-Year Change		
(Jan-Mar)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$17.51	$15.30	$7.84	NA	NA	NA
1999	$18.79	$16.56	$7.29	7.3%	8.3%	(7.0%)
2000	$23.66	$17.73	$16.22	25.9%	7.0%	122.4%
2001	$33.77	$26.01	$20.79	42.8%	46.8%	28.2%
2002	$22.23	$19.22	$9.61	(34.2%)	(26.1%)	(53.8%)
2003	$49.57	$43.08	$30.54	123.0%	124.2%	217.9%
2004	$46.37	$41.04	$24.07	(6.5%)	(4.8%)	(21.2%)
2005	$46.51	$40.62	$22.07	0.3%	(1.0%)	(8.3%)
2006	$52.98	$46.15	$23.29	13.9%	13.6%	5.5%
2007	$55.34	$47.15	$33.29	4.5%	2.2%	43.0%
2008	$66.75	$57.05	$35.54	20.6%	21.0%	6.8%
2009	$47.29	$40.56	$21.99	(29.2%)	(28.9%)	(38.1%)
2010	$44.13	$37.82	$21.87	(6.7%)	(6.8%)	(0.6%)
2011	$44.76	$38.14	$23.10	1.4%	0.8%	5.6%
2012	$30.38	$28.82	$11.63	(32.1%)	(24.4%)	(49.7%)

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 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 LMP, each weighted by the PJM total hourly load.

PJM Real-Time, Load-Weighted, Average LMP

Table 2-23 shows the PJM real-time, load-weighted, average LMP for the first quarter of the 15-year period 1998 to 2012.

Table 2-23 PJM real-time, load-weighted, average LMP (Dollars per MWh): January through March, 1998 through 2012 (See 2011 SOM, Table 2-37)

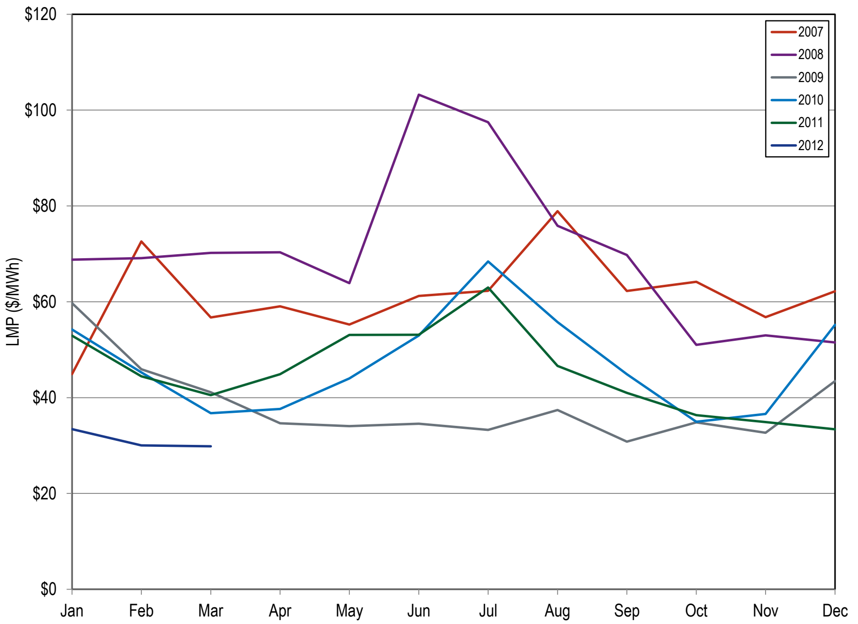
	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Mar)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$18.13	$15.80	$8.14	NA	NA	NA
1999	$19.38	$16.90	$7.66	6.9%	7.0%	(5.9%)
2000	$25.10	$18.25	$17.22	29.5%	8.0%	124.9%
2001	$35.16	$27.38	$21.52	40.1%	50.0%	25.0%
2002	$23.01	$19.89	$9.93	(34.6%)	(27.4%)	(53.8%)
2003	$51.93	$46.12	$30.99	125.6%	131.9%	211.9%
2004	$48.77	$43.22	$24.62	(6.1%)	(6.3%)	(20.6%)
2005	$48.37	$42.20	$22.62	(0.8%)	(2.4%)	(8.1%)
2006	$54.43	$47.62	$23.69	12.5%	12.9%	4.7%
2007	$58.07	$50.60	$34.44	6.7%	6.3%	45.4%
2008	$69.35	$60.11	$36.56	19.4%	18.8%	6.2%
2009	$49.60	$42.23	$23.38	(28.5%)	(29.8%)	(36.1%)
2010	$45.92	$39.01	$22.99	(7.4%)	(7.6%)	(1.7%)
2011	$46.35	$39.11	$24.26	0.9%	0.3%	5.5%
2012	$31.21	$29.25	$12.02	(32.7%)	(25.2%)	(50.5%)

32 The system annual, average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

PJM Real-Time, Monthly, Load-Weighted, Average LMP

Figure 2-16 shows the PJM real-time, monthly, load-weighted LMP from 2007 through the first quarter of 2012.

Figure 2-16 PJM real-time, monthly, load-weighted, average LMP: 2007 through March of 2012 (See 2011 SOM, Figure 2-16)



Fuel Price Trends and 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 efficiency, 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. Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. Both coal and natural gas decreased in price in the first quarter of 2012. Comparing prices on March 31, 2012 to prices on December 31, 2011, the price of Northern Appalachian coal was 7.3 percent lower; the price of Central Appalachian coal was 14.4 percent lower; the price of Powder River Basin coal was 12.1 percent lower; the price of eastern natural gas was 37.7 percent lower; and the price of western natural gas was 38.8 percent lower. Figure 2-17 shows spot average fuel prices for 2011 and 2012.[33]

Figure 2-17 Spot average fuel price comparison: 2011 and January through March 2012 (See 2011 SOM, Figure 2-17)

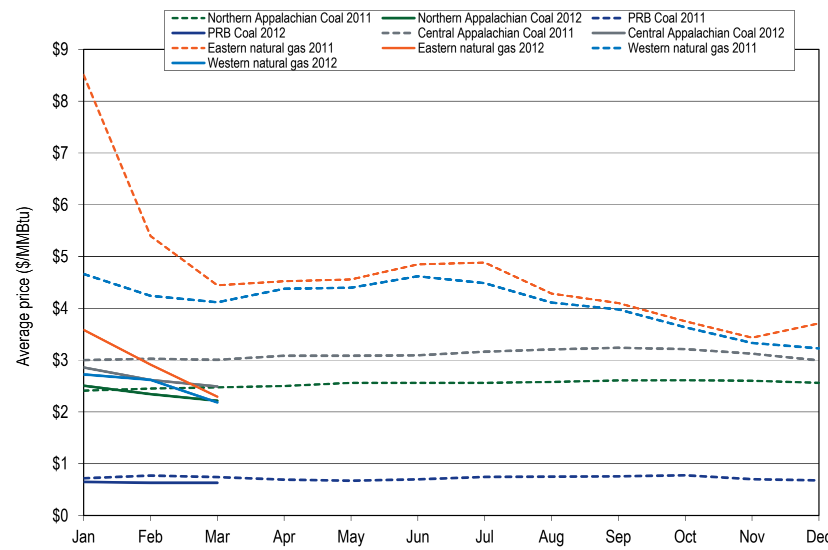


Figure 2-12 shows the spot average cost of generation, comparing the fuel cost of a coal plant, combined cycle, and combustion turbine in dollars per MWh. On average, the fuel cost of a new entrant combined cycle unit was lower than the fuel cost of a new entrant coal plant in the first three months of 2012.

33 Eastern natural gas, Western natural gas, light oil, and heavy oil prices are the average of daily fuel price indices in the PJM footprint. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

Figure 2-18 Spot average fuel cost of generation of CP, CT, and CC: 2011 and January through March 2012 (New Figure)

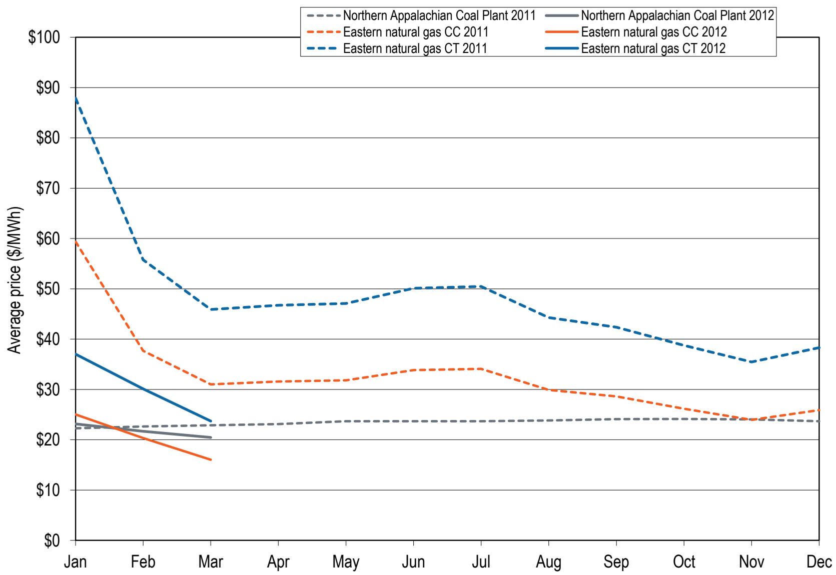
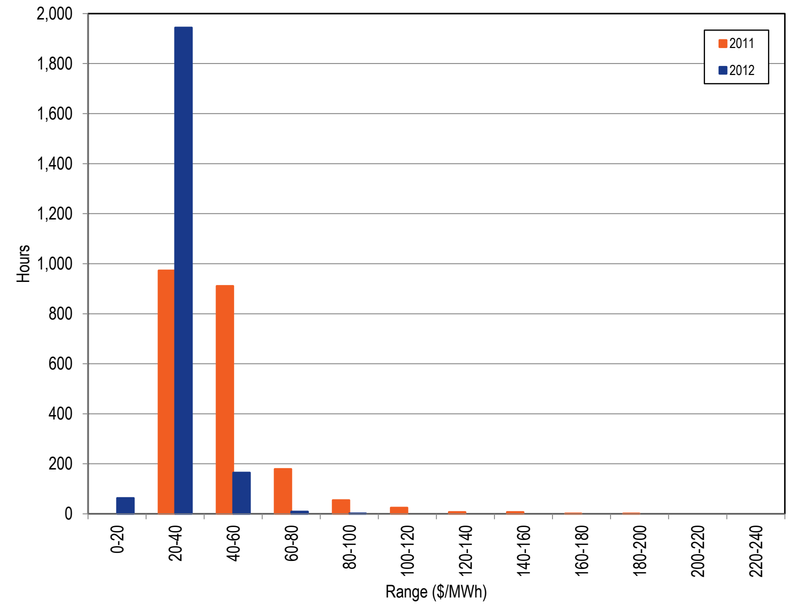


Figure 2-19 Price histogram for the PJM Day-Ahead Energy Market: January through March, 2011 and 2012 (See 2011 SOM, Figure 2-18)



Day-Ahead LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[34] This section discusses the day-ahead average LMP and the day-ahead load weighted average LMP. Average LMP is the simple, unweighted average LMP.

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 2-19 shows the hourly distribution of PJM day-ahead average LMP for the first quarter of 2011 and 2012.

34 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for detailed definition of Day-Ahead LMP.

PJM Day-Ahead, Average LMP

Table 2-24 shows the PJM day-ahead, average LMP for the first quarter of the 12 year period 2001 to 2012.

Table 2-24 PJM day-ahead, average LMP (Dollars per MWh): January through March, 2001 through 2012 (See 2011 SOM, Table 2-40)

	Day-Ahead LMP			Year-to-Year Change		
(Jan-Mar)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.45	$32.72	$16.39	NA	NA	NA
2002	$22.43	$20.59	$7.56	(38.5%)	(37.1%)	(53.9%)
2003	$51.20	$46.06	$25.65	128.2%	123.7%	239.3%
2004	$45.84	$43.01	$18.85	(10.5%)	(6.6%)	(26.5%)
2005	$45.14	$41.56	$16.19	(1.5%)	(3.4%)	(14.1%)
2006	$51.23	$48.53	$14.16	13.5%	16.8%	(12.6%)
2007	$52.76	$49.43	$22.59	3.0%	1.9%	59.5%
2008	$66.10	$62.57	$23.90	25.3%	26.6%	5.8%
2009	$47.41	$43.43	$16.85	(28.3%)	(30.6%)	(29.5%)
2010	$46.13	$41.99	$15.93	(2.7%)	(3.3%)	(5.5%)
2011	$45.60	$41.10	$16.82	(1.2%)	(2.1%)	5.6%
2012	$31.86	$30.56	$6.49	(30.1%)	(25.6%)	(61.4%)

Day-Ahead, Load-Weighted, Average LMP

Day-ahead, load-weighted LMP reflects the average LMP paid for day-ahead MWh. Day-ahead, load-weighted LMP is the average of PJM day-ahead hourly LMP, each weighted by the PJM total cleared day-ahead hourly load, including day-ahead fixed load, price-sensitive load, decrement bids and up-to congestion.

PJM Day-Ahead, Load-Weighted, Average LMP

Table 2-25 shows the PJM day-ahead, load-weighted, average LMP for the first quarter of the 12-year period 2001 to 2012.

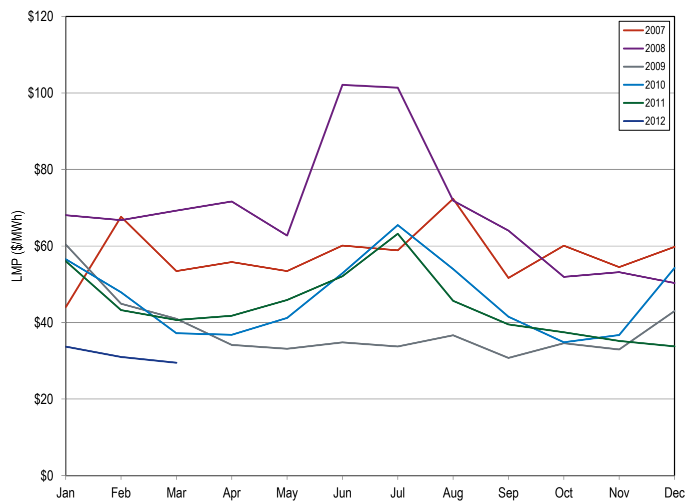
Table 2-25 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through March, 2001 through 2012 (See 2011 SOM, Table 2-41)

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Mar)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$37.70	$34.55	$16.66	NA	NA	NA
2002	$23.17	$21.18	$7.76	(38.5%)	(38.7%)	(53.4%)
2003	$53.16	$48.69	$25.75	129.5%	129.9%	231.7%
2004	$47.75	$45.02	$19.19	(10.2%)	(7.5%)	(25.4%)
2005	$46.54	$42.88	$16.46	(2.5%)	(4.8%)	(14.2%)
2006	$52.40	$49.51	$14.29	12.6%	15.5%	(13.2%)
2007	$54.87	$51.89	$23.16	4.7%	4.8%	62.0%
2008	$68.00	$64.70	$24.35	23.9%	24.7%	5.1%
2009	$49.44	$44.85	$17.54	(27.3%)	(30.7%)	(28.0%)
2010	$47.77	$43.62	$16.52	(3.4%)	(2.7%)	(5.8%)
2011	$47.14	$42.49	$17.73	(1.3%)	(2.6%)	7.3%
2012	$31.51	$30.44	$6.83	(33.2%)	(28.3%)	(61.5%)

PJM Day-Ahead, Monthly, Load-Weighted, Average LMP

Figure 2-20 shows the PJM day-ahead, monthly, load-weighted LMP from 2007 through the first quarter of 2012.

Figure 2-20 Day-ahead, monthly, load-weighted, average LMP: 2007 through March of 2012 (See 2011 SOM, Figure 2-19)



Virtual Offers and Bids

There is a substantial volume of virtual offers and bids in the PJM Day-Ahead Market and such offers and bids may each be marginal, based on the way in which the PJM optimization algorithm works.

Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids and up-to congestion transactions as financial instruments that do not require physical generation or load. Increment offers, decrement bids and up-to congestion transactions may be submitted at any hub, transmission zone, aggregate, or single bus for which LMP is calculated.[35] Table 2-26 shows the average volume of trading in increment offers and decrement bids per hour and the average total MW values of all bids per hour. Table 2-27 shows the average volume of up-to congestion transactions per hour and the average total MW values of all bids per hour.

Table 2-26 Hourly average volume of cleared and submitted INCs, DECs by month: 2011 through March of 2012 (See 2011 SOM, Table 2-43)

		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2011	Jan	8,137	14,299	218	1077	11,135	17,917	224	963
2011	Feb	8,530	16,263	215	1672	11,071	17,355	230	1034
2011	Mar	7,230	13,164	201	1059	10,435	16,343	219	982
2011	Apr	7,222	12,516	185	984	10,211	16,199	202	846
2011	May	7,443	12,161	220	835	10,250	15,956	243	800
2011	Jun	8,405	14,171	238	1084	11,648	17,542	279	1015
2011	Jul	8,595	14,006	185	1234	12,196	17,567	213	1140
2011	Aug	7,540	12,349	120	1034	10,992	15,368	161	847
2011	Sep	7,092	10,071	114	591	12,171	16,268	147	648
2011	Oct	7,726	10,242	104	351	10,983	14,550	116	396
2011	Nov	8,290	11,545	105	382	10,936	15,204	118	416
2011	Dec	8,914	12,159	107	409	11,964	15,515	114	404
2011	Annual	7,792	12,924	180	992	11,109	16,507	203	867
2012	Jan	6,781	10,341	91	455	9,031	12,562	111	428
2012	Feb	6,428	10,930	96	591	7,641	11,043	108	511
2012	Mar	5,969	9,051	90	347	7,193	10,654	112	362
2012	Annual	6,393	10,107	92	464	7,955	11,419	110	434

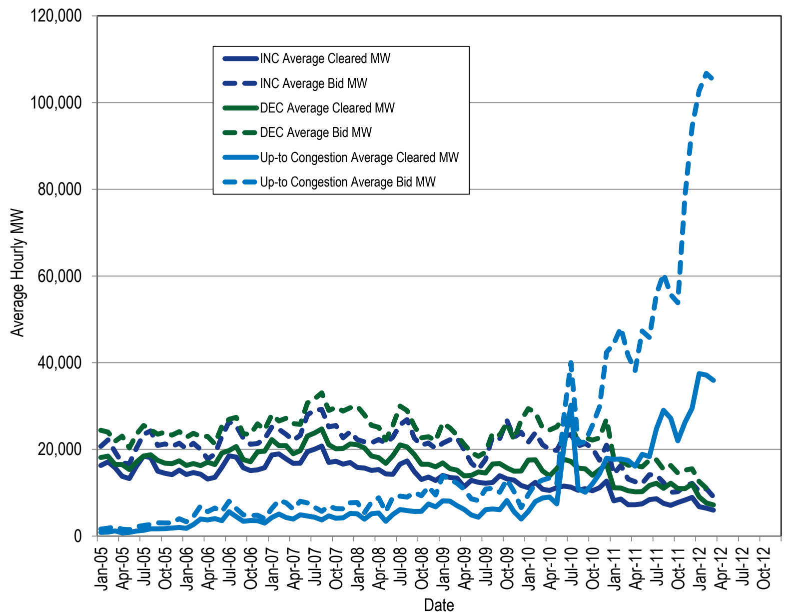
Table 2-27 Hourly average of cleared and submitted up-to congestion bids by month: 2011 through March of 2012 (See 2011 SOM, Table 2-44)

		Up-to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2011	Jan	17,687	44,361	338	779
2011	Feb	17,759	48,052	386	877
2011	Mar	17,451	41,666	419	940
2011	Apr	16,114	38,182	488	1,106
2011	May	18,854	47,312	560	1,199
2011	Jun	18,323	45,802	508	1,141
2011	Jul	24,742	55,809	641	1,285
2011	Aug	28,996	60,531	654	1,348
2011	Sep	27,184	55,706	638	1,267
2011	Oct	21,985	53,830	616	1,345
2011	Nov	26,234	78,486	718	1,682
2011	Dec	29,471	94,316	720	1,837
2011	Annual	22,067	55,338	557	1,234
2012	Jan	37,469	102,762	805	1,950
2012	Feb	37,132	106,741	830	2,115
2012	Mar	35,921	105,222	865	2,224
2012	Annual	36,841	104,908	833	2,096

35 An import up-to congestion transaction must source at an interface, but may sink at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. An export up-to congestion transaction may source at any hub, transmission zone, aggregate, or single bus for which LMP is calculated, but must sink at an interface. Wheeling up-to congestion transactions must both source and sink at an interface.

Figure 2-21 shows the hourly volume of bid and cleared INC, DEC and up-to congestion bids by month.

Figure 2-21 Hourly volume of bid and cleared INC, DEC and Up-to Congestion bids (MW) by month: January, 2005 through March, 2012 (See 2011 SOM, Figure 2-20)



In order to evaluate the ownership of virtual bids, the MMU categorized all participants making virtual bids 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. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 2-28 shows the total increment offers and decrement bids by the type of parent organization: financial or physical. Table 2-29 shows the total up-to congestion transactions by the type of parent organization: financial or physical.

Table 2-28 PJM INC and DEC bids by type of parent organization (MW): January through March, 2011 and 2012 (See 2011 SOM, Table 2-46)

	2011 (Jan-Mar)		2012 (Jan-Mar)	
Category	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	35,013,405	51.1%	17,564,197	37.4%
Physical	33,470,237	48.9%	29,408,939	62.6%
Total	68,483,641	100.0%	46,973,136	100.0%

Table 2-29 PJM up-to congestion transactions by type of parent organization (MW): January through March, 2011 and 2012 (See 2011 SOM, Table 2-47)

	2011 (Jan-Mar)		2012 (Jan-Mar)	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	36,721,026	96.8%	76,787,244	95.1%
Physical	1,355,931	3.2%	3,931,378	4.9%
Total	38,076,956	100.0%	80,718,623	100.0%

Table 2-30 shows increment offers and decrement bids bid by top ten locations.

Table 2-30 PJM virtual offers and bids by top ten locations (MW): January through March, 2011 and 2012 (See 2011 SOM, Table 2-48)

2011 (Jan-Mar)					2012 (Jan-Mar)				
Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	6,426,945	6,902,555	13,329,499	WESTERN HUB	HUB	7,688,302	8,954,480	16,642,782
N ILLINOIS HUB	HUB	2,625,577	4,527,187	7,152,764	AEP-DAYTON HUB	HUB	1,311,830	1,322,353	2,634,183
AEP-DAYTON HUB	HUB	1,480,675	1,641,866	3,122,541	SOUTHIMP	INTERFACE	2,362,472	0	2,362,472
SOUTHIMP	INTERFACE	1,731,983	0	1,731,983	N ILLINOIS HUB	HUB	797,387	1,217,638	2,015,025
MISO	INTERFACE	68,374	1,244,714	1,313,088	PECO	ZONE	569,142	1,413,636	1,982,778
PECO	ZONE	296,203	999,453	1,295,655	PPL	ZONE	109,230	1,461,786	1,571,016
PPL	ZONE	104,239	993,763	1,098,001	MISO	INTERFACE	68,763	1,325,083	1,393,845
IMO	INTERFACE	808,906	85,891	894,798	IMO	INTERFACE	1,095,465	7,054	1,102,519
COMED	ZONE	680,972	165,165	846,137	PSEG	ZONE	211,672	342,435	554,108
BGE	ZONE	48,094	762,176	810,270	BGE	ZONE	53,894	446,806	500,700
		14,271,967	17,322,770	31,594,736			14,268,157	16,491,270	30,759,427
PJM total		31,347,701	37,135,940	68,483,641			22,025,564	24,947,572	46,973,136
Top ten total as percent of PJM total		45.5%	46.6%	46.1%			64.8%	66.1%	65.5%

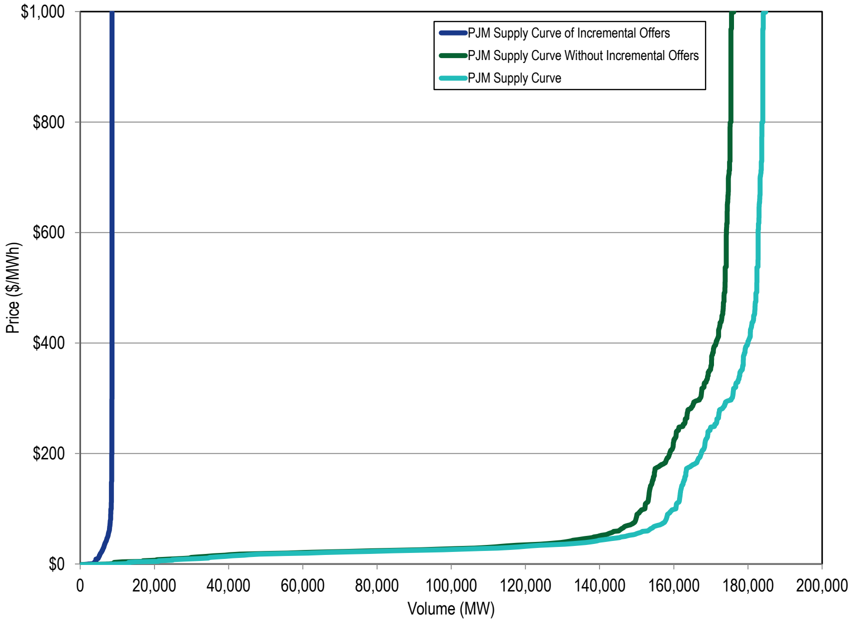
Table 2-31 shows up-to congestion transactions by import, export and wheel for the top ten locations.

Table 2-31 PJM cleared up-to congestion import, export and wheel bids by top ten source and sink pairs (MW): January through March, 2011 and 2012 (See 2011 SOM, Table 2-49)

							2011 (Jan-Mar)							
		Imports					Exports					Wheels		
Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	112 WILTON	EHVAGG	1,071,503	WESTERN HUB	HUB	MISO	INTERFACE	851,201	NORTHWEST	INTERFACE	SOUTHWEST	AGGREGATE	133,090
MISO	INTERFACE	N ILLINOIS HUB	HUB	932,389	23 COLLINS	EHVAGG	MISO	INTERFACE	841,950	NORTHWEST	INTERFACE	MISO	INTERFACE	90,509
NORTHWEST	INTERFACE	ZION 1	AGGREGATE	750,284	BEAV DUQ UNIT1	AGGREGATE	MICHFE	AGGREGATE	649,505	NYIS	INTERFACE	MICHFE	AGGREGATE	60,290
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	486,580	21 KINCA ATR24304	AGGREGATE	SOUTHWEST	AGGREGATE	579,542	SOUTHWEST	AGGREGATE	OVEC	INTERFACE	55,425
NORTHWEST	INTERFACE	BRAIDWOOD 1	AGGREGATE	448,342	21 KINCA ATR24304	AGGREGATE	OVEC	INTERFACE	455,450	NCMPAIMP	INTERFACE	OVEC	INTERFACE	49,289
OVEC	INTERFACE	STUART 1	AGGREGATE	401,442	COOK	EHVAGG	OVEC	INTERFACE	338,754	MISO	INTERFACE	NIPSCO	INTERFACE	49,248
OVEC	INTERFACE	CONESVILLE 6	AGGREGATE	374,351	QUAD CITIES 2	AGGREGATE	MISO	INTERFACE	288,843	SOUTHEAST	AGGREGATE	CPLEEXP	INTERFACE	46,200
NORTHWEST	INTERFACE	112 WILTON	EHVAGG	333,682	STUART 1	AGGREGATE	OVEC	INTERFACE	260,156	NIPSCO	INTERFACE	OVEC	INTERFACE	41,081
NYIS	INTERFACE	MARION	AGGREGATE	289,556	SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	208,808	NIPSCO	INTERFACE	MISO	INTERFACE	35,408
NYIS	INTERFACE	PSEG	ZONE	277,926	21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	202,774	SOUTHEAST	AGGREGATE	IMO	INTERFACE	24,194
Top ten total				5,366,053					4,676,983					584,733
PJM total				21,828,666					15,408,100					840,190
Top ten total as percent of PJM total				24.6%					30.4%					69.6%
							2012 (Jan-Mar)							
		Imports					Exports					Wheels		
Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	112 WILTON	EHVAGG	3,950,243	ROCKPORT	EHVAGG	OVEC	INTERFACE	1,653,313	MISO	INTERFACE	NORTHWEST	INTERFACE	50,943
OVEC	INTERFACE	CONESVILLE 4	AGGREGATE	1,372,477	ROCKPORT	EHVAGG	SOUTHWEST	AGGREGATE	1,079,308	NIPSCO	INTERFACE	NORTHWEST	INTERFACE	18,738
OVEC	INTERFACE	DEOK	ZONE	1,064,356	23 COLLINS	EHVAGG	MISO	INTERFACE	931,276	SOUTHWEST	AGGREGATE	OVEC	INTERFACE	13,961
OVEC	INTERFACE	CONESVILLE 5	AGGREGATE	752,791	167 PLANO	EHVAGG	MISO	INTERFACE	757,345	NORTHWEST	INTERFACE	MISO	INTERFACE	13,833
MISO	INTERFACE	N ILLINOIS HUB	HUB	724,225	SPORN 3	AGGREGATE	OVEC	INTERFACE	646,956	SOUTHEAST	AGGREGATE	SOUTHWEST	AGGREGATE	11,601
OVEC	INTERFACE	CONESVILLE 6	AGGREGATE	701,270	WESTERN HUB	HUB	MISO	INTERFACE	633,292	SOUTHWEST	AGGREGATE	SOUTHEXP	INTERFACE	10,572
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	616,066	SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	570,882	OVEC	INTERFACE	SOUTHEXP	INTERFACE	9,346
MISO	INTERFACE	POWERTON 5	AGGREGATE	615,189	ROCKPORT	EHVAGG	MISO	INTERFACE	544,717	NYIS	INTERFACE	NEPTUNE	INTERFACE	8,786
NYIS	INTERFACE	HUDSON BC	AGGREGATE	523,487	QUAD CITIES 1	AGGREGATE	NORTHWEST	INTERFACE	536,568	NORTHWEST	INTERFACE	SOUTHEXP	INTERFACE	8,593
MISO	INTERFACE	COOK	EHVAGG	418,931	SPORN 5	AGGREGATE	OVEC	INTERFACE	530,900	NIPSCO	INTERFACE	IMO	INTERFACE	7,855
Top ten total				10,739,036					7,884,555					154,227
PJM total				39,854,574					40,363,681					227,583
Top ten total as percent of PJM total				26.9%					19.5%					67.8%

Figure 2-22 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve without increment offers and the system aggregate supply curve with increment offers for an example day in March 2012.

Figure 2-22 PJM day-ahead aggregate supply curves: 2012 example day (See 2011 SOM, Figure 2-21)



Price Convergence

The introduction of the PJM Day-Ahead Energy Market created the possibility that competition, exercised through the use of virtual offers and bids, would tend to cause prices in the Day-Ahead and Real-Time Energy Markets to converge. Convergence is not the goal of virtual trading but it is a possible outcome. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Market. 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 differences in risk, that result in a competitive, market-based differential. In addition, convergence in the sense that Day-Ahead and Real-Time prices are equal at individual buses or aggregates is not a realistic expectation. PJM markets do not provide a mechanism that could result in convergence 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 reflect 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. Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative (Figure 2-23). There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis (Figure 2-24).

As Table 2-32 shows, day-ahead and real-time prices were relatively close, on average, in the first quarter of 2011 and 2012.

Table 2-32 Day-ahead and real-time average LMP (Dollars per MWh): January through March, 2011 and 2012[36] (See 2011 SOM, Table 2-50)

	2011 (Jan - Mar)				2012 (Jan - Mar)			
	Day Ahead	Real Time	Difference	Difference as Percent of Real Time	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$45.60	$44.76	($0.84)	(1.9%)	$30.82	$30.38	($0.43)	(1.4%)
Median	$41.10	$38.14	($2.96)	(7.8%)	$30.04	$28.82	($1.22)	(4.2%)
Standard deviation	$16.82	$23.10	$6.27	27.2%	$6.63	$11.63	$5.00	43.0%
Peak average	$50.24	$49.26	($0.98)	(2.0%)	$33.78	$33.75	($0.03)	(0.1%)
Peak median	$45.77	$42.16	($3.61)	(8.6%)	$32.08	$30.65	($1.43)	(4.7%)
Peak standard deviation	$16.21	$23.06	$6.86	29.7%	$6.30	$12.05	$5.75	47.7%
Off peak average	$41.41	$40.70	($0.71)	(1.7%)	$28.19	$27.41	($0.79)	(2.9%)
Off peak median	$36.85	$34.85	($2.00)	(5.7%)	$27.75	$26.75	($1.00)	(3.7%)
Off peak standard deviation	$16.27	$22.37	$6.10	27.3%	$5.76	$10.38	$4.62	44.5%

The price difference between the Real-Time and the Day-Ahead Energy Markets results, in part, from volatility in the Real-Time Energy Market that is difficult, or impossible, to anticipate in the Day-Ahead Energy Market.

Table 2-33 shows the difference between the Real-Time and the Day-Ahead Energy Market Prices for the first quarter of 2001 to 2012.

Table 2-33 Day-ahead and real-time average LMP (Dollars per MWh): January through March, 2001 through 2012 (See 2011 SOM, Table 2-51)

(Jan - Mar)	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2001	$36.45	$33.77	($2.68)	(7.3%)
2002	$22.43	$22.23	($0.20)	(0.9%)
2003	$51.20	$49.57	($1.63)	(3.2%)
2004	$45.84	$46.37	$0.52	1.1%
2005	$45.14	$46.51	$1.37	3.0%
2006	$51.23	$52.98	$1.75	3.4%
2007	$52.76	$55.34	$2.58	4.9%
2008	$66.10	$66.75	$0.65	1.0%
2009	$47.41	$47.29	($0.12)	(0.2%)
2010	$46.13	$44.13	($2.00)	(4.3%)
2011	$45.60	$44.76	($0.84)	(1.8%)
2012	$30.82	$30.38	($0.43)	(1.4%)

Table 2-34 provides frequency distributions of the differences between PJM real-time load-weighted hourly LMP and PJM day-ahead load-weighted hourly LMP for the first quarter of years 2007 through 2012.

36 The averages used are the annual average of the hourly average PJM prices for day-ahead and real-time.

Table 2-34 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): January through March, 2007 through 2012 (See 2011 SOM, Table 2-52)

	2007		2008		2009		2010		2011		2012	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($150) to ($100)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.05%	0	0.00%
($100) to ($50)	14	0.65%	21	0.96%	1	0.05%	5	0.23%	17	0.83%	2	0.09%
($50) to $0	1,214	56.88%	1,309	60.93%	1,347	62.44%	1,569	72.90%	1,464	68.64%	1,566	71.83%
$0 to $50	847	96.11%	740	94.82%	788	98.93%	547	98.24%	619	97.31%	601	99.36%
$50 to $100	73	99.49%	97	99.27%	21	99.91%	33	99.77%	51	99.68%	12	99.91%
$100 to $150	7	99.81%	14	99.91%	2	100.00%	1	99.81%	6	99.95%	2	100.00%
$150 to $200	0	99.81%	1	99.95%	0	100.00%	4	100.00%	1	100.00%	0	100.00%
$200 to $250	1	99.86%	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$250 to $300	1	99.91%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$300 to $350	2	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$350 to $400	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$400 to $450	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$450 to $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Figure 2-23 shows the hourly differences between day-ahead and real-time load-weighted hourly LMP in the first quarter of 2012.

Figure 2-23 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: January through March, 2012 (See 2011 SOM, Figure 2-22)

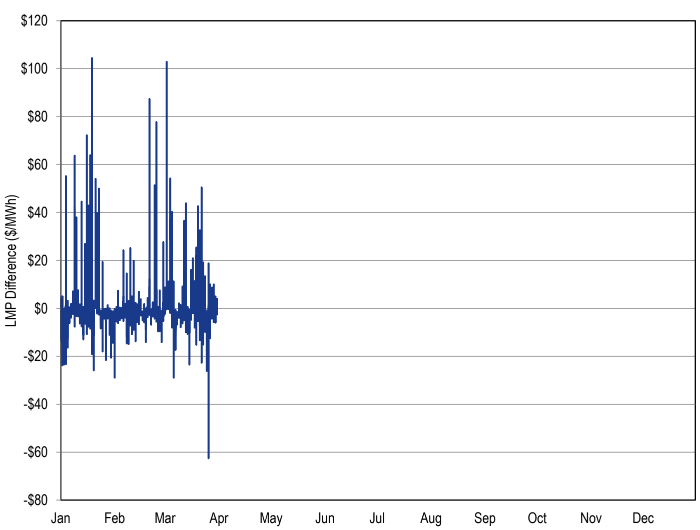
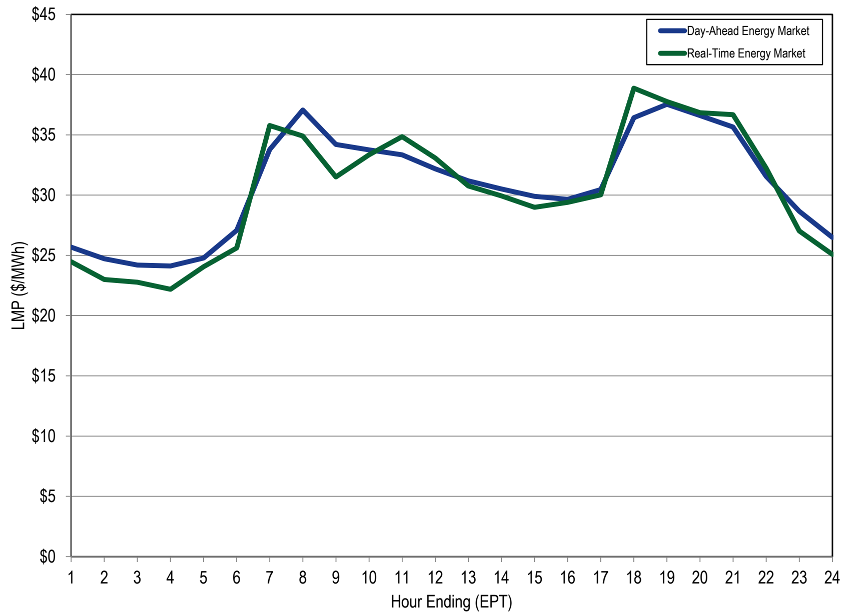


Figure 2-24 shows the monthly average differences between the day-ahead and real-time LMP in the first quarter of 2012.

Figure 2-24 Monthly average of real-time minus day-ahead LMP: January through March, 2012 (See 2011 SOM, Figure 2-23)

Figure 2-25 shows day-ahead and real-time LMP on an average hourly basis.

Figure 2-25 PJM system hourly average LMP: January through March, 2012 (See 2011 SOM, Figure 2-24)



Load and Spot Market

Real-Time Load and Spot Market

Participants in the PJM Real-Time Energy Market can use their own generation to meet load, to sell in the bilateral market or to sell in the spot market in any hour. Participants can both buy and sell via bilateral contracts and buy and sell in the spot market in any hour. If a participant has positive net bilateral transactions in an hour, it is buying energy through bilateral contracts (bilateral purchase). If a participant has negative net bilateral transactions in an hour, it is selling energy through bilateral contracts (bilateral sale). If a participant has positive net spot transactions in an hour, it is buying energy from the spot market (spot purchase). If a participant has negative net spot transactions in an hour, it is selling energy to the spot market (spot sale).

Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In addition to directly serving load, load serving entities can also transfer their responsibility to serve load to other parties through eSchedules transactions referred to as wholesale load responsibility (WLR) or retail load responsibility (RLR) transactions. When the responsibility to serve load is transferred via a bilateral contract, the entity to which the responsibility is transferred becomes the load serving entity. Supply from its own generation (self-supply) means that the parent company is generating power from plants that it owns in order to meet demand. Supply from bilateral purchases means that the parent company is purchasing power under bilateral contracts from a non-affiliated company at the same time that it is meeting load. Supply from spot market purchases means that the parent company is not generating enough power from owned plants and/or not purchasing enough power under bilateral contracts to meet load at a defined time and, therefore, is purchasing the required balance from the spot market.

The PJM system's reliance on self-supply, bilateral contracts and spot purchases to meet real-time load is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Real-Time Energy Market for each hour. Table 2-35 shows the monthly average share of real-time load served by self-supply, bilateral contract and spot purchase in 2011 and 2012 based on parent company. For 2012, 10.2 percent of real-time load was supplied by bilateral contracts, 23.3 percent by spot market purchase and 66.5 percent by self-supply. Compared with 2011, reliance on bilateral contracts decreased 01.3 percentage points, reliance on spot supply decreased by 3.3 percentage points and reliance on self-supply increased by 3.6 percentage points.

Table 2-35 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2011 through 2012 (See 2011 SOM, Table 2-53)

	2011			2012			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	9.3%	28.8%	61.9%	10.0%	23.2%	66.9%	0.7%	(5.6%)	5.0%
Feb	10.9%	27.9%	61.2%	10.2%	22.3%	67.5%	(0.7%)	(5.6%)	6.3%
Mar	10.4%	29.3%	60.3%	10.6%	24.5%	64.8%	0.3%	(4.8%)	4.5%
Apr	10.7%	25.3%	64.1%						
May	11.1%	25.7%	63.3%						
Jun	10.5%	25.4%	64.1%						
Jul	9.5%	24.7%	65.8%						
Aug	10.3%	24.6%	65.1%						
Sep	10.9%	26.7%	62.4%						
Oct	12.2%	29.8%	58.0%						
Nov	10.7%	28.3%	61.1%						
Dec	10.1%	24.3%	65.5%						
Annual	10.5%	26.6%	62.9%	10.2%	23.3%	66.5%	(0.3%)	(3.3%)	3.6%

Day-Ahead Load and Spot Market

In the PJM Day-Ahead Energy Market, participants can not only use their own generation, bilateral contracts and spot market purchases to supply their load serving obligation, but can also use virtual resources to meet their load serving obligations in any hour. Virtual supply is treated as generation in the day-ahead analysis and virtual demand is treated as demand in the day-ahead analysis.

The PJM system's reliance on self-supply, bilateral contracts, and spot purchases to meet day-ahead load (cleared fixed-demand, price-sensitive load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Day-Ahead Energy Market for each hour. Table 2-36 shows the monthly average share of day-ahead load served by self-supply, bilateral contracts and spot purchases in 2011 and 2012, based on parent companies. For 2012, 7.2 percent of day-ahead load was supplied by bilateral contracts, 22.7 percent by spot market purchases, and 70.1 percent by self-supply. Compared with 2011, reliance on bilateral contracts increased by 1.4 percentage points, reliance on spot supply decreased by 1.7 percentage points, and reliance on self-supply increased by 0.3 percentage points.

Table 2-36 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: 2011 through 2012 (See 2011 SOM, Table 2-54)

	2011			2012			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	4.7%	23.7%	71.6%	7.1%	22.4%	70.5%	2.4%	(1.3%)	(1.1%)
Feb	5.4%	23.7%	70.9%	7.3%	21.3%	71.4%	1.9%	(2.4%)	0.5%
Mar	5.8%	24.3%	70.0%	7.3%	24.4%	68.2%	1.6%	0.2%	(1.7%)
Apr	6.1%	23.8%	70.1%						
May	6.0%	24.0%	70.0%						
Jun	6.0%	25.3%	68.8%						
Jul	5.5%	23.4%	71.2%						
Aug	5.7%	24.1%	70.1%						
Sep	5.8%	25.2%	69.0%						
Oct	5.7%	25.7%	68.5%						
Nov	6.4%	25.3%	68.3%						
Dec	6.6%	25.3%	68.1%						
Annual	5.8%	24.4%	69.8%	7.2%	22.7%	70.1%	1.4%	(1.7%)	0.3%