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 2013, 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 2013.

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 2013 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1200 with a minimum of 1047 and a maximum of 1409 in the first three months of 2013.
- 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 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 the exercise of 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.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.
- Market performance was evaluated as competitive because market results in the Energy Market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.
- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes, with prices reflecting, on average, the marginal cost to produce energy. In aggregate, PJM's Energy Market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design mitigates market power and causes the market to provide competitive market outcomes.

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

1 Analysis of 2013 market results requires comparison to prior years. In 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 *2012 State of the Market Report for PJM*, Appendix A, "PJM Geography."

2 OATT Attachment M

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]

Overview

Market Structure

- **Supply.** Average offered supply increased by 4,230, or 2.4 percent, from 173,590 MW in the first three months of 2012 to 177,820 MW in the first three months of 2013.[4] The increase in offered supply was in part the result of 362 MW of new capacity added to PJM in 2013. This new supply was partially offset by the deactivation of 2 units (169 MW) since January 1, 2013.
- **Demand.** The PJM system peak load for the first three months of 2013 was 126,632 MW in the HE 1900 on January 22, 2013, which was 4,093 MW, or 3.3 percent, higher than the PJM peak load for the first three months of 2012, which was 122,539 MW in the HE 1900 on January 3, 2013.[5]
- **Market Concentration.** Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.
- **Local Market Structure and Offer Capping.** PJM continued to apply a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in the first three months of 2013. PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer capping levels have historically been low in PJM. In the first three months of 2013, offer capping levels increased as a result of the inclusion of units that are committed for reliability reasons to provide black start and reactive service. In the Day-Ahead Energy Market offer-capped unit hours increased from 0.1 percent in the first three months of 2012 to 4.1 percent in the first three months of 2013. In the Real-Time Energy Market offer-capped unit hours increased from 1.9 percent in the first three months of 2012 to 3.6 percent in the first three months of 2013.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 48 units eligible for FMU or AU status in at least one month during the first three months of 2013, 35 units (72.9 percent) were FMUs or AUs for all three months, and 7 units (14.6 percent) qualified in only one month of 2013.

  The MMU recommends the elimination of FMU and AU adders. FMU and AU adders were added to the market rules in 2006 in order to address revenue inadequacy for frequently mitigated units. Since that time, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007, and significant changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.
- **Local Market Structure.** In the first three months of 2013, 11 Control Zones experienced congestion resulting from one or more constraints binding for 25 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.

Market Performance: Markup, Load, Generation and LMP

- **Markup.** The markup conduct of individual owners and units has an impact on market prices. The markup analysis is a key indicator of the competitiveness of the Energy Market.

  All generating units, including coal units, are allowed to include a 10 percent adder in their cost offer. The 10 percent adder was included in the

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.
4 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.
5 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2012 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).

definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. Coal units do not face the same cost uncertainty as gas-fired CTs. A review of actual participant behavior supports this view, as the owners of coal units, facing competition, typically remove the 10 percent adder from their actual offers. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder from the cost offer. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the 10 percent adder in the cost offer.

In the first three months of 2013, the unadjusted markup was negative, primarily as a result of competitive behavior by coal units. The unadjusted markup component of LMP was -$2.69 per MWh. The adjusted markup was less negative, -$0.95 per MWh or -2.5 percent of the PJM real-time, load-weighted average LMP of $37.41 per MWh.

The overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or close to their marginal costs. This is strong evidence of competitive behavior and competitive market performance.

- **Load.** PJM average real-time load in the first three months of 2013 increased by 5.8 percent from the first three months of 2012, from 86,329 MW to 91,337 MW.

  PJM average day-ahead load in the first three months of 2013, including DECs and up-to congestion transactions, increased by 11.1 percent from the first three months of 2012, from 129,258 MW to 143,585 MW. The day-ahead load growth was 91.4 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions.

- **Generation.** PJM average real-time generation in the first three months of 2013 increased by 5.3 percent from the first three months of 2012, from 88,068 MW to 92,776 MW.

  PJM average day-ahead generation in the first three months of 2013, including INCs and up-to congestion transactions, increased by 11.4 percent from the first three months of 2012, from 132,178 MW to 147,246 MW. The day-ahead generation growth was 109.4 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.

  The MMU recommends that PJM real-time and day-ahead generation be calculated using gross generation instead of net generation. What PJM treats as negative generation is actually load and should be included in the calculations of PJM real-time and day-ahead load.

- **Generation Fuel Mix.** During the first three months of 2013, coal units provided 44.5 percent, nuclear units 35.5 percent and gas units 15.1 percent of total generation. Compared to the first three months of 2012, generation from coal units increased 16.2 percent, generation from nuclear units increased 2.0 percent, and generation from gas units decreased 17.2 percent. This represents a reversal of the recent trend of decreasing coal-fired output and increasing gas-fired output. The change is primarily a result of increased natural gas prices in the first three months of 2013, particularly in eastern zones, and lower or constant coal prices.

- **Prices.** 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 and local price differences caused by congestion.

  PJM Real-Time Energy Market prices increased in the first three months of 2013 compared to the first three months of 2012. The system average LMP was 19.6 percent higher in the first three months of 2013 than in the first three months of 2012, $36.33 per MWh versus $30.38 per MWh. The load-weighted average LMP was 19.9 percent higher in the first three months of 2013 than in the first three months of 2012, $37.41 per MWh versus $31.21 per MWh.

  PJM Day-Ahead Energy Market prices increased in the first three months of 2013 compared to the first three months of 2012. The system average LMP was 18.3 percent higher in the first three months of 2013 than in the first three months of 2012, $36.46 per MWh versus $30.82 per MWh. The load-weighted average LMP was 18.3 percent higher in the first three months of 2013 than in the first three months of 2012, $37.26 per MWh versus $31.51 per MWh.[6]

There is currently no documentation addressing how hubs are defined and changed in the tariff or manuals. The MMU recommends that PJM include in the appropriate manual the process of initially defining hubs and the the process for approving additions, deletions and changes to hub definitions. According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

- **Load and Spot Market.** Companies that serve load in PJM can do so using 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. For the first three months of 2013, 10.5 percent of real-time load was supplied by bilateral contracts, 22.8 percent by spot market purchase and 66.8 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased 1.4 percentage points, reliance on spot supply decreased by 0.4 percentage points and reliance on self-supply decreased by 1.0 percentage points. For the first three months of 2013, 6.9 percent of day-ahead load was supplied by bilateral contracts, 22.6 percent by spot market purchases, and 70.5 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased by 0.2 percentage points, reliance on spot supply increased by 0.3 percentage points, and reliance on self-supply decreased by 0.5 percentage points.

6 Tables reporting zonal and jurisdictional load and prices are in the *2012 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

Scarcity

- **Scarcity Pricing Events in 2013.** PJM's market did not experience any reserve-based shortage events in the first three months of 2013.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in the first three months of 2013, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand-side response programs, loads and prices.

Average real-time supply offered increased by 4,230 MW in the first three months of 2013 compared to the first three months of 2012, while peak load increased by 4,093 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. In the Day-Ahead Energy Market, average load in the first three months of 2013 increased from the first three months of 2012, from 129,258 MW to 143,585 MW, or 11.1 percent. In the Real-Time Energy Market, average load in the first three months of 2013 increased from the first three months of 2012, from 86,329 MW to 91,337 MW, or 5.8 percent. 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-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 in each hour. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and 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 2013 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.[7] 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.

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. PJM implemented new scarcity pricing rules in 2012. There are significant issues with the scarcity pricing true up mechanism in the new PJM scarcity pricing design, which will create issues when scarcity pricing occurs.

The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior remain potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in the first three months of 2013.

Market Structure

Supply

Average offered supply increased by 4,230 MW, or 2.4 percent, from 173,590 MW in the first three months of 2012 to 177,820 MW in the first three months of 2013.[8] The increase in offered supply was in part the result of 362 MW of new capacity added to PJM in 2013. This new supply was partially offset by the deactivation of 2 units (169 MW) since January 1, 2013.

Figure 2-1 shows the average PJM aggregate supply curves, peak load and average load for the first three months of 2012 and 2013.

7 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.

8 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.

Figure 2-1 Average PJM aggregate supply curves: January through March of 2012 and 2013

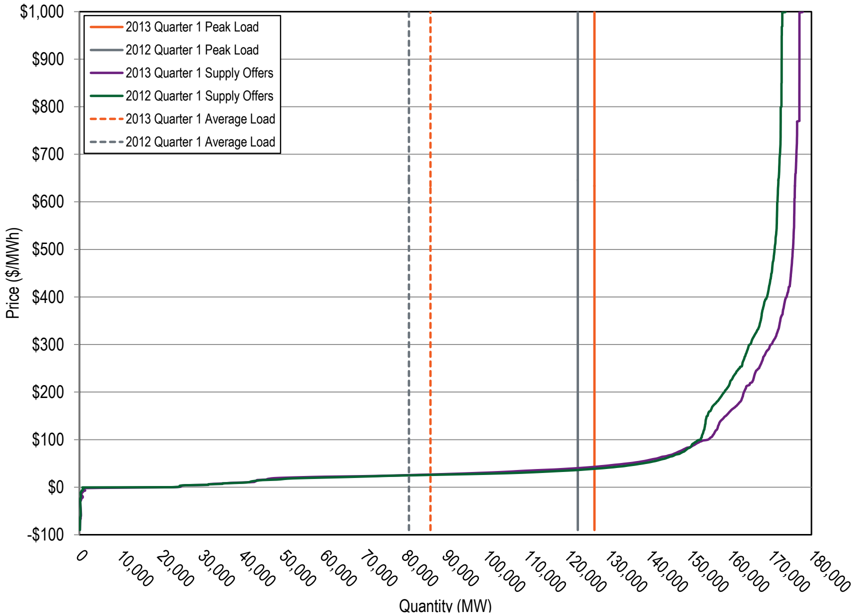


Table 2-2 PJM generation (By fuel source (GWh)): January through March 2012 and 2013[9]

	Jan-Mar 2012		Jan-Mar 2013		Change in
	GWh	Percent	GWh	Percent	Output
Coal	77,680.5	39.9%	90,256.4	44.5%	16.2%
Standard Coal	75,124.3	38.6%	87,586.9	43.2%	16.0%
Waste Coal	2,556.2	1.3%	2,669.5	1.3%	0.1%
Nuclear	70,637.4	36.3%	72,028.7	35.5%	2.0%
Gas	36,995.2	19.0%	30,636.8	15.1%	(17.2%)
Natural Gas	36,413.7	18.7%	30,075.7	14.8%	(17.4%)
Landfill Gas	581.3	0.3%	561.1	0.3%	(3.5%)
Biomass Gas	0.1	0.0%	0.0	0.0%	(99.9%)
Hydroelectric	3,357.9	1.7%	3,576.8	1.8%	6.5%
Wind	4,191.6	2.2%	4,788.1	2.4%	14.2%
Waste	1,249.0	0.6%	1,191.0	0.6%	(4.6%)
Solid Waste	979.3	0.5%	951.5	0.5%	(2.8%)
Miscellaneous	269.7	0.1%	239.5	0.1%	(11.2%)
Oil	357.4	0.2%	136.5	0.1%	(61.8%)
Heavy Oil	318.9	0.2%	105.5	0.1%	(66.9%)
Light Oil	37.2	0.0%	23.4	0.0%	(36.9%)
Diesel	1.1	0.0%	0.7	0.0%	(37.9%)
Kerosene	0.2	0.0%	6.9	0.0%	3,764.8%
Jet Oil	0.0	0.0%	0.0	0.0%	116.9%
Solar	43.2	0.0%	59.8	0.0%	38.5%
Battery	0.0	0.0%	0.1	0.0%	271.7%
Total	194,512.3	100.0%	202,674.2	100.0%	4.2%

Energy Production by Fuel Source

Compared to the first three months of 2012, generation from coal units increased 16.2 percent and generation from natural gas units decreased 17.4 percent (Table 2-2). This represents a reversal of the recent trend of decreasing coal-fired output and increasing gas-fired output. The change is primarily a result of increased natural gas prices in the first three months of 2013, particularly in eastern zones, and lower or constant coal prices.

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

Table 2-3 Monthly PJM Generation (By fuel source (GWh)): January through March 2013

	Jan	Feb	Mar	Total
Coal	31,689.2	28,886.8	29,680.4	90,256.4
Standard Coal	30,814.3	28,102.4	28,670.2	87,586.9
Waste Coal	874.9	784.4	1,010.2	2,669.5
Nuclear	25,610.7	22,563.1	23,854.9	72,028.7
Gas	10,261.4	10,319.8	10,055.6	30,636.8
Natural Gas	10,072.4	10,143.6	9,859.7	30,075.7
Landfill Gas	189.0	176.2	195.9	561.1
Biomass Gas	0.0	0.0	0.0	0.0
Hydroelectric	1,234.0	1,127.0	1,215.8	3,576.8
Wind	1,784.4	1,397.5	1,606.2	4,788.1
Waste	414.4	385.2	391.5	1,191.0
Solid Waste	324.8	301.5	325.2	951.5
Miscellaneous	89.6	83.7	66.2	239.5
Oil	62.5	23.8	50.3	136.5
Heavy Oil	55.8	21.9	27.9	105.5
Light Oil	4.2	1.5	17.7	23.4
Diesel	0.6	0.1	0.0	0.7
Kerosene	1.9	0.3	4.7	6.9
Jet Oil	0.0	0.0	0.0	0.0
Solar	15.6	17.6	26.7	59.8
Battery	0.1	0.0	0.0	0.1
Total	71,072.0	64,720.7	66,881.4	202,674.2

Generator Offers

The generator offers are categorized by dispatchable and self-scheduled MW and are shown in Table 2-4 and Table 2-5.[10,11] Table 2-4 shows the average hourly distribution of MW for dispatchable units by offer prices for the first three months of 2013. Table 2-5 shows the average hourly distribution of MW for self-scheduled units by offer prices for the first three months of 2013. Of the dispatchable MW offered by combustion turbines (CT), 27.7 percent were dispatchable at an offered range of $600 to $800. Only wind and solar units have negative offer prices.

10 Each range in the tables is greater than or equal to the lower value and less than the higher value.
11 The unit type battery is not included in these tables because batteries do not make energy offers.

Table 2-4 Distribution of MW for dispatchable unit offer prices: January through March of 2013

	Dispatchable (Range)						
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Total
CC	0.0%	61.2%	13.8%	3.5%	3.5%	1.0%	82.9%
CT	0.0%	38.3%	21.4%	8.0%	27.7%	4.2%	99.6%
Diesel	0.0%	7.3%	51.8%	7.7%	1.2%	0.8%	68.9%
Hydro	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.3%
Nuclear	0.0%	9.8%	0.0%	0.0%	0.0%	0.0%	9.8%
Pumped Storage	0.0%	51.5%	0.0%	0.0%	0.0%	0.0%	51.5%
Solar	0.0%	44.1%	0.0%	0.0%	0.0%	0.0%	44.1%
Steam	0.0%	50.4%	9.9%	0.7%	0.1%	0.0%	61.1%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	26.0%	30.3%	0.0%	0.0%	0.0%	0.0%	56.3%
All Dispatchable Offers	0.7%	40.6%	10.4%	2.4%	6.1%	1.0%	61.3%

Table 2-5 Distribution of MW for self-scheduled unit offer prices: January through March of 2013

	Self-Scheduled (Range)						
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Total
CC	0.0%	14.3%	2.7%	0.1%	0.0%	0.0%	17.1%
CT	0.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.4%
Diesel	0.0%	30.8%	0.1%	0.0%	0.0%	0.2%	31.1%
Hydro	0.0%	98.5%	0.0%	0.0%	0.0%	1.2%	99.7%
Nuclear	0.0%	90.2%	0.0%	0.0%	0.0%	0.0%	90.2%
Pumped Storage	0.0%	48.5%	0.0%	0.0%	0.0%	0.0%	48.5%
Solar	7.3%	48.6%	0.0%	0.0%	0.0%	0.0%	55.9%
Steam	0.0%	25.5%	13.1%	0.0%	0.3%	0.1%	38.9%
Transaction	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	11.6%	32.1%	0.0%	0.0%	0.0%	0.0%	43.7%
All Self-Scheduled Offers	0.3%	32.2%	5.9%	0.0%	0.1%	0.1%	38.7%

Demand

The PJM system peak load for the first three months 2013 was 126,632 MW in the HE 1900 on January 22, 2013, which was 4,093 MW, or 3.3 percent, higher than the PJM peak load for the first three months of 2012, which was 122,539 MW in the HE 1900 on January 3, 2012.

Table 2-6 shows the coincident peak loads for the first three months of 1999 through 2013.

Table 2-6 Actual PJM footprint peak loads: January through March of 1999 to 2013[12]

(Jan - Mar)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Thu, January 14	18	40,413	NA	NA
2000	Thu, January 27	19	42,445	2,032	5.0%
2001	Tue, January 02	19	41,142	(1,303)	(3.1%)
2002	Wed, January 02	19	39,458	(1,684)	(4.1%)
2003	Thu, January 23	19	54,670	15,212	38.6%
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	Tue, January 03	19	122,539	11,880	10.7%
2013	Tue, January 22	19	126,632	4,093	3.3%

Figure 2-2 shows the peak loads for the first three months of 1999 through 2013.

Figure 2-2 PJM footprint calendar year peak loads: January through March of 1999 to 2013[13]

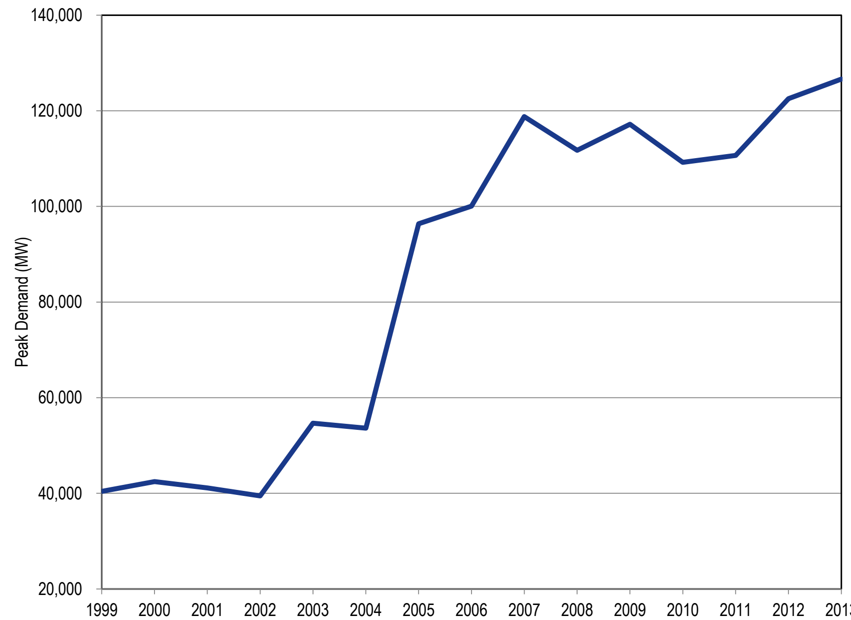


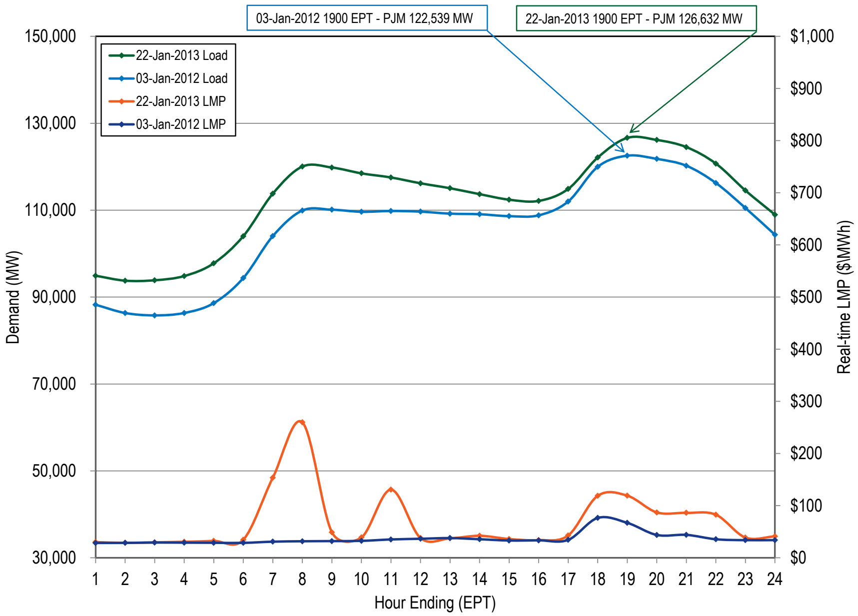
Figure 2-3 compares the peak load days in the first three months of 2012 and 2013. In every hour on January 22, 2013, the average hourly real-time load was higher than the average hourly real-time load on January 3, 2012. The average hourly real-time LMP peaked at $259.80 on January 22, 2013 and peaked at $76.50 on January 3, 2012. The higher real-time LMP for hours 7, 8 and 11 on January 22, 2013 was triggered by a large MW unit tripping resulting in loss of reserves. Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes energy and ancillary services. The abrupt change in generation output resulted in energy units being redispatched to increase reserves for meeting ancillary service requirements. The joint optimization takes into account the lost opportunity cost of lowered generation in calculating LMPs and the incremental cost to maintain reserves. During the hours 7, 8 and 9 of January 22, 2013 higher LMPs reflect the

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

13 For additional information on the "PJM Integration Period", see the *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

lost opportunity cost of generators providing reserve at the expense of not providing energy.

Figure 2-3 PJM peak-load comparison: Tuesday, January 22, 2013, and Tuesday, January 3, 2012



Market Concentration

Analyses of supply curve segments of the PJM Energy Market for the first three months of 2013 indicate moderate concentration in the base load segment, but high concentration in the intermediate and peaking segments.[14] 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 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 2013. 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.

The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market. Hourly PJM Energy Market HHIs were calculated based on the real-time energy output of generators, adjusted for hourly net imports by owner (Table 2-7).

Hourly HHIs were also calculated for baseload, intermediate and peaking segments of generation supply. Hourly Energy Market HHIs by supply curve segment were calculated based on hourly Energy Market shares, unadjusted for imports.

The "Merger Policy Statement" of the FERC states that a market can be broadly characterized as:

- **Unconcentrated.** Market HHI below 1000, equivalent to 10 firms with equal market shares;
- **Moderately Concentrated.** Market HHI between 1000 and 1800; and
- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[15]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during the first three months of 2013 was moderately concentrated (Table 2-7).

14 A unit is classified as base load if it runs for more than 50 percent of the total hours, as intermediate if it runs for less than 50 percent but greater than 10 percent of the total hours, and as peak if it runs for less than 10 percent of the total hours.

15 Order No. 592, "*Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement*," 77 FERC ¶ 61,263, pp. 64-70 (1996)

Table 2-7 PJM hourly Energy Market HHI: January through March, 2012[16] and 2013

	Hourly Market HHI (Jan - Mar, 2012)	Hourly Market HHI (Jan - Mar, 2013)
Average	1235	1200
Minimum	1107	1047
Maximum	1499	1409
Highest market share (One hour)	28%	28%
Average of the highest hourly market share	22%	21%
# Hours	2,183	2,159
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 2-8 includes 2013 HHI values by supply curve segment, including base, intermediate and peaking plants.

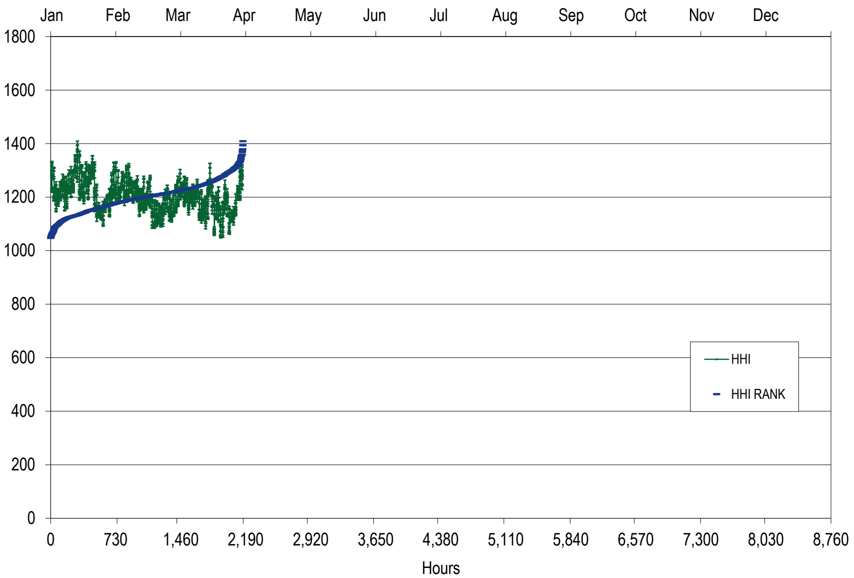
Table 2-8 PJM hourly Energy Market HHI (By supply segment): January through March, 2012 and 2013

	Jan - Mar, 2012			Jan - Mar, 2013		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	1110	1239	1496	1082	1205	1410
Intermediate	1160	2916	7597	1204	3526	8784
Peak	966	6682	10000	914	6987	10000

Figure 2-4 presents the 2013 hourly HHI values in chronological order and an HHI duration curve.

16 This analysis includes all hours in the first three months of 2013, regardless of congestion.

Figure 2-4 PJM hourly Energy Market HHI: January through March, 2013



Local Market Structure and Offer Capping

In the PJM Energy Market, offer capping occurs as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets. PJM also uses offer capping for units that are committed for reliability reasons, specifically for providing black start and reactive service. 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 2-9. The offer capping percentages shown in Table 2-9 include all the units that are committed on their cost schedule, when their price schedule is available. This includes units that are committed to provide constraint relief whose owners failed the TPS test in the energy market, as well as units that are committed for reliability reasons to provide black start and reactive service.

Table 2-9 Offer-capping statistics: January through March, 2009 to 2013

	Real Time		Day Ahead	
(Jan - Mar)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2009	0.5%	0.2%	0.2%	0.1%
2010	0.6%	0.2%	0.1%	0.0%
2011	0.6%	0.2%	0.0%	0.0%
2012	1.9%	1.3%	0.1%	0.2%
2013	3.6%	2.2%	4.1%	2.1%

Table 2-10 presents data on the frequency with which units were offer capped in the first three months of 2012 and 2013.

Table 2-10 Real-time offer-capped unit statistics: January through March, 2012 and 2013

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	(Jan - Mar)	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
	2013	11	0	0	0	0	29
90%	2012	0	0	0	0	3	53
	2013	8	0	0	0	0	5
80% and < 90%	2012	2	0	0	0	0	7
	2013	4	0	0	1	0	2
75% and < 80%	2012	1	0	0	0	0	3
	2013	1	0	0	0	0	2
70% and < 75%	2012	2	0	0	0	0	7
	2013	2	0	0	0	0	9
60% and < 70%	2012	2	0	0	1	0	15
	2013	0	0	0	0	2	11
50% and < 60%	2012	2	0	0	2	2	18
	2013	0	0	3	0	1	26
25% and < 50%	2012	4	0	3	1	1	16
	2013	0	0	1	0	3	16
10% and < 25%	2012	0	1	2	1	3	14

Table 2-10 shows that a significant number of units are offer capped for 90 percent or more of their run hours in the first three months of 2013. The increase in the number of units that are capped for a high percentage of their run hours reflects the units that are committed specifically for reliability reasons.

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 2013, the AEP, AP, ATSI, BGE, ComEd, Dominion, PECO, PENELEC, Pepco, PPL 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 2013.[17] The AECO, DAY, DEOK, DLCO, DPL, JCPL, Met-Ed 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, 2013, through March 31, 2013. 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.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and

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

does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small.

Table 2-11 Three pivotal supplier test details for regional constraints: January through March, 2013

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	282	332	13	2	11
	Off Peak	172	282	12	3	8
AP South	Peak	278	419	9	1	9
	Off Peak	305	476	9	1	8
Bedington - Black Oak	Peak	156	139	11	2	10
	Off Peak	NA	NA	NA	NA	NA
Eastern	Peak	463	619	16	2	14
	Off Peak	NA	NA	NA	NA	NA
Western	Peak	456	533	12	1	10
	Off Peak	NA	NA	NA	NA	NA

Table 2-12 Summary of three pivotal supplier tests applied for regional constraints: January through March, 2013

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	570	50	9%	14	2%	28%
	Off Peak	378	41	11%	8	2%	20%
AP South	Peak	2,936	158	5%	26	1%	16%
	Off Peak	1,632	67	4%	9	1%	13%
Bedington - Black Oak	Peak	11	0	0%	0	0%	0%
	Off Peak	NA	NA	NA	NA	NA	NA
Eastern	Peak	8	0	0%	0	0%	0%
	Off Peak	NA	NA	NA	NA	NA	NA
Western	Peak	5	1	20%	0	0%	0%
	Off Peak	NA	NA	NA	NA	NA	NA

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 owners passing and failing for the regional 500 kV constraints.

The three pivotal supplier test is applied every time the PJM market system solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for capping. Only uncommitted resources, which would be started as a result of incremental relief needs, are eligible to be offer capped. Already committed units that can provide incremental relief cannot, regardless of test score, be switched from price to cost offers. Table 2-12 provides, for the identified 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.

Ownership of Marginal Resources

Table 2-13 shows the contribution to PJM real-time, annual, load-weighted LMP by individual marginal resource owner.[18] The contribution of each marginal resource to price at each load bus is calculated for the first three months of 2013, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. The results show that in the first three months of 2013, the offers of one company contributed 26.2 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 58.1 percent of the real-time, load-weighted, average PJM system LMP. In comparison, during the first three months of 2012, the offers of one company contributed 24.4 percent of the real time, load-weighted PJM system LMP and offers of the top four

18 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

companies contributed 58.5 percent of the real-time, load-weighted, average PJM system LMP.

Table 2-13 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): January through March, 2012 and 2013

2012 (Jan - Mar)		2013 (Jan - Mar)	
Company	Percent of Price	Company	Percent of Price
1	24.4%	1	26.2%
2	15.7%	2	11.4%
3	9.4%	3	10.7%
4	8.9%	4	9.9%
5	8.1%	5	7.8%
6	4.2%	6	5.2%
7	3.9%	7	4.4%
8	3.9%	8	3.5%
9	3.7%	9	3.3%
Other (37 companies)	17.7%	Other (45 companies)	17.8%

Table 2-14 shows the contribution to PJM day-ahead, load-weighted LMP by individual marginal resource owner.[19] The contribution of each marginal resource to price at each load bus is calculated for the first three months of 2013, period and summed by the company that offers the marginal resource into the Day-Ahead Energy Market.

Table 2-14 Marginal unit contribution to PJM day-ahead, load-weighted LMP (By parent company): January through March, 2012 and 2013

2012 (Jan - Mar)		2013 (Jan - Mar)	
Company	Percent of Price	Company	Percent of Price
1	17.4%	1	20.1%
2	8.7%	2	9.0%
3	7.7%	3	8.7%
4	7.5%	4	4.0%
5	6.8%	5	3.8%
6	3.9%	6	3.7%
7	3.9%	7	3.6%
8	3.6%	8	3.4%
9	2.9%	9	3.1%
Other (98 companies)	37.6%	Other (115 companies)	40.6%

19 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Type of Marginal Resources

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. Marginal resource designation is not limited to physical resources, particularly in the Day-Ahead Market. INC offers, DEC bids and up-to congestion transactions are dispatchable injections and withdrawals in the Day-Ahead Market that can set price via their offers and bids.

Table 2-15 shows the type of fuel used by marginal resources in the Real-Time Energy Market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first three months of 2013, coal units were 61.5 percent and natural gas units were 30.8 percent of the total marginal resources. In the first three months of 2012, coal units were 60.9 percent and natural gas units were 27.3 percent of the total marginal resources.[20]

Table 2-15 Type of fuel used (By real-time marginal units): January through March, 2012 and 2013

Fuel Type	2012 (Jan - Mar)	2013 (Jan - Mar)
Coal	60.9%	61.5%
Gas	27.3%	30.8%
Municipal Waste	0.2%	0.1%
Oil	4.3%	1.8%
Other	0.2%	0.1%
Uranium	0.0%	0.0%
Wind	7.1%	5.7%

Table 2-16 shows the type, and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first three months of 2013, Up-to Congestion transactions were 95.4 percent of the total marginal resources. In comparison, Up-to Congestion transactions were 84.8 percent of the total marginal resources in the first three months of 2012.

20 The percentages of marginal fuel reported in the *2011 State of the Market Report for PJM*, Volume I, were based on both Locational Pricing Algorithm (LPA) and dispatch (SCED) marginal resources. Starting from *2012 State of the Market Report for PJM*, marginal fuel percentages are based only on resources that were marginal in dispatch (SCED). See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table 2-16 Day-ahead marginal resources by type/fuel: January through March, 2012 and 2013

Type/Fuel	2012 (Jan - Mar)	2013 (Jan - Mar)
Up-to Congestion Transaction	84.8%	95.4%
DEC	5.8%	1.2%
INC	5.5%	1.0%
Coal	2.7%	1.6%
Gas	0.9%	0.7%
Price Sensitive Demand	0.1%	0.0%
Dispatchable Transaction	0.1%	0.1%
Wind	0.0%	0.0%
Oil	0.0%	0.0%
Municipal Waste	0.0%	0.0%
Total	100.0%	100.0%

Market Conduct: Markup

The markup index is a summary measure of participant offer behavior or conduct for individual marginal units. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[21] 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, to reflect their relative importance in the system dispatch solution. The markup index does not measure the impact of unit markup on total LMP.

Real-Time Mark Up Conduct

Table 2-17 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category. A unit is assigned to a price category for each dispatch solution associated with the interval in which it was marginal, based on its offer price at that time. The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point.

Table 2-17 Average, real-time marginal unit markup index (By price category): January through March, 2012 and 2013

	2012 (Jan - Mar)			2013 (Jan - Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.07)	($2.75)	29.5%	(0.08)	($3.04)	18.0%
$25 to $50	(0.06)	($2.87)	53.1%	(0.04)	($2.55)	62.1%
$50 to $75	0.02	($0.78)	3.3%	0.01	($0.60)	6.7%
$75 to $100	0.32	$27.64	0.2%	0.04	$3.39	1.5%
$100 to $125	0.22	$22.17	0.4%	0.02	$2.23	1.2%
$125 to $150	0.49	$62.73	0.1%	0.02	$2.27	0.9%
>= $150	0.04	$8.01	5.0%	0.01	$0.14	4.1%

Day-Ahead Mark Up Conduct

Table 2-18 shows the average markup index of marginal units in Day-Ahead Energy Market, by offer price category. A unit is assigned to a price category for each interval in which it was marginal, based on its offer price at that time.

Table 2-18 Average marginal unit markup index (By offer price category): January through March, 2012 and 2013

	2012 (Jan - Mar)			2013 (Jan - Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.08)	($2.55)	27.4%	(0.05)	($1.55)	17.1%
$25 to $50	(0.07)	($3.40)	70.3%	(0.05)	($2.96)	77.1%
$50 to $75	0.03	$0.97	2.3%	0.01	($2.48)	5.2%
$75 to $100	0.00	$0.00	0.0%	0.08	$6.63	0.5%
$100 to $125	0.00	$0.00	0.0%	0.00	$0.00	0.1%
$125 to $150	0.00	$0.00	0.0%	0.00	$0.00	0.0%
>= $150	0.00	$0.00	0.0%	0.00	$0.00	0.0%

21 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00), the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

Market Performance

Markup

The markup index, which is a measure of participant conduct for individual marginal units, does not measure the impact of participant 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. 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.[22]

The price impact of markup must be interpreted carefully. The markup calculation is not based on a full 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 calculated an explicit measure of the impact of marginal unit markups on LMP. The markup impact includes the 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.

Real-Time Markup

Markup Component of Real-Time Price by Fuel, Unit Type

The markup component of price is the difference between the system price, when the system price is determined by marginal units with price-based offers, and the system price, based on the cost-based offers of those marginal units.

Table 2-19 shows the average unit markup component of LMP for marginal units, by unit type and primary fuel. The markup component of LMP is a measure of the impact of the markups of marginal units shown in Table 2-19 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 2-17.

22 This is the same method used to calculate the fuel-cost-adjusted LMP and the components of LMP.

Table 2-19 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through March, 2012 and 2013[23]

		2012 (Jan - Mar)		2013 (Jan - Mar)	
Fuel Type	Unit Type	Markup Component of LMP	Percent	Markup Component of LMP	Percent
Coal	Steam	($2.05)	80.2%	($1.08)	40.2%
Gas	CC	($0.23)	9.1%	($1.42)	53.0%
Gas	CT	($0.20)	7.8%	($0.26)	9.5%
Gas	Diesel	$0.00	0.0%	$0.00	(0.0%)
Gas	Steam	($0.01)	0.4%	$0.07	(2.4%)
Municipal Waste	Diesel	$0.00	0.0%	$0.00	0.0%
Municipal Waste	Steam	$0.04	(1.7%)	$0.00	(0.0%)
Oil	CT	$0.00	(0.0%)	($0.00)	0.0%
Oil	Diesel	$0.00	(0.0%)	$0.00	(0.0%)
Oil	Steam	($0.11)	4.4%	($0.00)	0.1%
Other	Solar	$0.00	0.0%	$0.00	(0.0%)
Other	Steam	($0.01)	0.3%	($0.00)	0.1%
Uranium	Steam	$0.00	0.0%	$0.00	0.0%
Wind	Wind	$0.01	(0.4%)	$0.01	(0.4%)
TOTAL		($2.55)	100.0%	($2.69)	100.0%

Markup Component of Real-Time System Price

Table 2-20 shows the markup component of average prices and of average monthly on-peak and off-peak prices. In the first three months of 2013, -$2.69 per MWh of the PJM real-time, load-weighted average LMP was attributable to markup. In the first three months of 2013, the markup component of LMP was -$3.37 per MWh off peak and -$2.02 per MWh on peak. In comparison, in the first three months of 2012, -$2.55 per MWh of the PJM real-time, load-weighted average LMP was attributable to markup. In the first three months of 2012, the markup component of LMP was -$3.02 per MWh off peak and -$2.10 per MWh on peak.

Table 2-20 Monthly markup components of real-time load-weighted LMP: January through March, 2012 and 2013

	2012 (Jan - Mar)			2013 (Jan - Mar)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($3.25)	($3.51)	($2.98)	($4.05)	($4.42)	($3.70)
Feb	($2.07)	($2.92)	($1.26)	($2.61)	($3.87)	($1.38)
Mar	($2.24)	($2.51)	($2.00)	($1.33)	($1.85)	($0.80)
Total	($2.55)	($3.02)	($2.10)	($2.69)	($3.37)	($2.02)

Markup Component of Real-Time Zonal Prices

The annual average real-time price component of unit markup is shown for each zone in Table 2-21. While all were negative, the smallest zonal all hours average markup component for the first three months of 2013 was in the BGE Control Zone, -$3.03 per MWh, while the highest all hours' average zonal markup component for the first three months of 2013 was in the RECO Control Zone, -$1.20 per MWh. On peak, the smallest annual average zonal markup was in the PECO Control Zone, -$2.41 per MWh, while the highest annual average zonal markup was in the RECO Control Zone, -$0.19 per MWh.

23 The Unit Type Diesel refers to power generation using reciprocating internal combustion engines. Such Diesel units can use a variety of fuel types including diesel, natural gas, oil and municipal waste.

Table 2-21 Average real-time zonal markup component: January through March, 2012 and 2013

	2012 (Jan - Mar)			2013 (Jan - Mar)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	($2.52)	($3.53)	($1.51)	($2.90)	($3.58)	($2.22)
AEP	($2.73)	($3.17)	($2.28)	($2.73)	($3.05)	($2.40)
APS	($2.53)	($2.99)	($2.07)	($2.75)	($3.39)	($2.11)
ATSI	($2.88)	($3.43)	($2.35)	($2.60)	($3.00)	($2.22)
BGE	($2.30)	($1.89)	($2.71)	($3.03)	($4.05)	($1.99)
ComEd	($2.67)	($3.19)	($2.19)	($2.55)	($3.26)	($1.86)
DAY	($2.91)	($3.31)	($2.53)	($2.69)	($3.12)	($2.27)
DEOK	($2.87)	($3.17)	($2.58)	($2.65)	($3.11)	($2.20)
Dominion	($2.03)	($1.86)	($2.20)	($2.90)	($3.94)	($1.82)
DPL	($2.46)	($3.61)	($1.28)	($2.98)	($3.63)	($2.31)
DUQ	($2.67)	($2.98)	($2.36)	($2.52)	($3.00)	($2.06)
JCPL	($2.55)	($3.48)	($1.67)	($2.41)	($3.76)	($1.13)
Met-Ed	($2.62)	($3.53)	($1.75)	($2.70)	($3.38)	($2.05)
PECO	($2.53)	($3.55)	($1.55)	($2.94)	($3.49)	($2.41)
PENELEC	($2.75)	($3.41)	($2.11)	($2.50)	($3.13)	($1.89)
Pepco	($1.82)	($2.02)	($1.64)	($2.98)	($3.92)	($2.07)
PPL	($2.65)	($3.54)	($1.80)	($2.84)	($3.55)	($2.15)
PSEG	($2.53)	($3.48)	($1.65)	($1.86)	($2.88)	($0.89)
RECO	($2.46)	($3.63)	($1.44)	($1.20)	($2.34)	($0.19)

Markup by Real-Time System Price Levels

The price component measure uses load-weighted, price-based LMP and load-weighted LMP computed using cost-based offers for all marginal units. The markup component of price is computed by calculating the system price, based on the cost-based offers of the marginal units and comparing that to the actual system price to determine how much of the LMP can be attributed to markup.

Table 2-22 shows the average markup component of observed prices when the PJM system LMP was in the identified price range.

Table 2-22 Average real-time markup component (By price category): January through March, 2012 and 2013

	2012 (Jan - Mar)		2013 (Jan - Mar)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.67)	21.0%	($0.23)	8.3%
$25 to $50	($2.50)	74.1%	($2.28)	81.2%
$50 to $75	$0.27	2.7%	$0.02	5.3%
$75 to $100	$0.23	1.1%	($0.07)	1.4%
$100 to $125	$0.07	0.2%	($0.14)	0.7%
$125 to $150	$0.04	0.1%	($0.04)	0.2%
>= $150	$0.01	0.0%	$0.03	0.4%

Day-Ahead Markup

Markup Component of Day-Ahead Price by Fuel, Unit Type

The markup component of the overall PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 2-23.

Table 2-23 Markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through March, 2012 and 2013

		2012 (Jan - Mar)		2013 (Jan - Mar)	
Fuel Type	Unit Type	Markup Component of LMP	Percent	Markup Component of LMP	Percent
Coal	Steam	($1.94)	72.0%	($1.35)	49.3%
Gas	Steam	($0.62)	23.0%	($1.32)	48.2%
Oil	Steam	($0.10)	3.8%	($0.01)	0.2%
Gas	CT	($0.03)	1.2%	($0.06)	2.3%
Municipal Waste	Steam	($0.00)	0.1%	($0.00)	0.1%
Wind	Wind	($0.00)	0.0%	$0.00	0.0%
Total		($2.70)	100.0%	($2.74)	100.0%

Markup Component of Day-Ahead System Price

The markup component of day-ahead price is the difference between the day-ahead system price, when the day-ahead system price is determined by marginal units with price-based offers, and the day-ahead system price, based on the cost-based offers of those marginal units.

Table 2-24 shows the markup component of average prices and of average monthly on-peak and off-peak prices.

Table 2-24 Monthly markup components of day-ahead, load-weighted LMP: January through March, 2012 and 2013

	2012 (Jan - Mar)			2013 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($2.76)	($2.22)	($3.28)	($3.77)	($3.99)	($3.54)
Feb	($3.01)	($3.61)	($2.38)	($2.53)	($1.43)	($3.67)
Mar	($2.30)	($1.99)	($2.63)	($1.84)	($0.18)	($3.45)
Total	($2.70)	($2.61)	($2.79)	($2.74)	($1.94)	($3.55)

Markup Component of Day-Ahead Zonal Prices

The annual average price component of unit markup is shown for each zone in Table 2-25.

Table 2-25 Day-ahead, average, zonal markup component: January through March, 2012 and 2013

	2012 (Jan - Mar)			2013 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($3.32)	($3.47)	($3.16)	($2.98)	($2.31)	($3.67)
AEP	($2.55)	($2.35)	($2.75)	($2.62)	($1.76)	($3.48)
AP	($2.67)	($2.62)	($2.72)	($2.72)	($1.92)	($3.52)
ATSI	($2.68)	($2.56)	($2.81)	($2.75)	($1.85)	($3.70)
BGE	($2.85)	($2.93)	($2.78)	($2.77)	($2.14)	($3.41)
ComEd	($2.26)	($1.92)	($2.62)	($2.58)	($1.67)	($3.53)
DAY	($2.58)	($2.34)	($2.83)	($2.75)	($1.82)	($3.72)
DEOK	($2.55)	($2.41)	($2.69)	($2.63)	($1.68)	($3.60)
DLCO	($2.64)	($2.58)	($2.70)	($2.67)	($1.82)	($3.56)
DPL	($3.29)	($3.48)	($3.11)	($2.89)	($1.97)	($3.79)
Dominion	($2.51)	($2.35)	($2.66)	($2.69)	($2.02)	($3.32)
JCPL	($3.31)	($3.65)	($2.95)	($3.50)	($3.33)	($3.68)
Met-Ed	($2.98)	($2.94)	($3.02)	($2.90)	($2.24)	($3.59)
PECO	($3.27)	($3.41)	($3.13)	($2.84)	($2.02)	($3.69)
PENELEC	($2.77)	($2.65)	($2.89)	($2.70)	($1.80)	($3.65)
PPL	($3.04)	($3.05)	($3.04)	($2.99)	($2.34)	($3.65)
PSEG	($3.13)	($3.26)	($2.99)	($2.81)	($2.03)	($3.67)
Pepco	($2.72)	($2.75)	($2.69)	($2.74)	($2.11)	($3.39)
RECO	($2.99)	($3.16)	($2.80)	($2.78)	($1.90)	($3.76)

Markup by Day-Ahead System Price Levels

The annual average markup component of the identified price range and its frequency are shown in Table 2-26.

Table 2-26 shows the average markup component of observed price when the PJM day-ahead, system LMP was in the identified price range.

Table 2-26 Average, day-ahead markup (By LMP category): January through March, 2012 and 2013

	2012 (Jan - Mar)		2013 (Jan - Mar)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($3.35)	13.0%	($2.03)	3.1%
$25 to $50	($3.39)	86.2%	($3.74)	90.8%
$50 to $75	($0.61)	0.7%	$1.76	5.4%
$75 to $100	($0.95)	0.2%	$0.55	0.5%
$100 to $125	$0.00	0.0%	$0.02	0.2%
$125 to $150	$0.00	0.0%	$0.00	0.0%
>= $150	$0.00	0.0%	$0.00	0.0%

Frequently Mitigated Units and Associated Units

An FMU is a frequently mitigated unit. FMUs were first provided additional compensation as a form of scarcity pricing in 2005.[24] 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.[25] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.[26,27]

24 110 FERC ¶ 61,053 (2005).
25 OA, Schedule 1 § 6.4.2.
26 114 FERC ¶ 61, 076 (2006).
27 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).

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.

The MMU recommends the elimination of FMU and AU adders. FMU and AU adders were added to the market rules in 2006 in order to address revenue inadequacy for frequently mitigated units. Since that time, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007, and significant changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

FMUs and AUs are designated monthly, and a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[28]

Table 2-27 shows, by month, the number of FMUs and AUs in 2011 and 2012. For example, in January 2013, there were 18 FMUs and AUs in Tier 1, 17 FMUs and AUs in Tier 2, and 10 FMUs and AUs in Tier 3.

28 OA, Schedule 1 § 6.4.2. In 2007, the FERC approved OA revisions to clarify the AU criteria

Table 2-27 Number of frequently mitigated units and associated units (By month): 2012 and January through March 2013

	FMUs and AUs							
	2012				2013			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	26	21	52	99	18	17	10	45
February	26	22	47	95	18	11	12	41
March	25	17	47	89	18	8	12	38
April	23	17	46	86				
May	23	14	47	84				
June	22	13	48	83				
July	25	11	50	86				
August	25	23	43	91				
September	17	6	33	56				
October	10	18	14	42				
November	9	21	10	40				
December	14	17	10	41				

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.

Figure 2-5 Frequently mitigated units and associated units (By month): February, 2006 through March, 2013

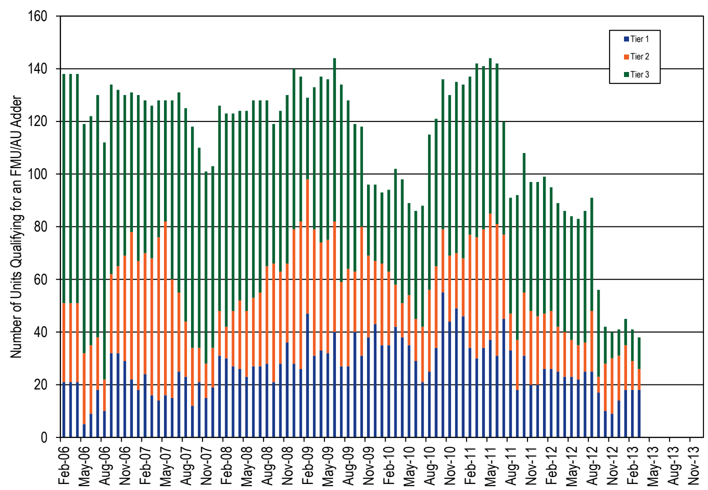


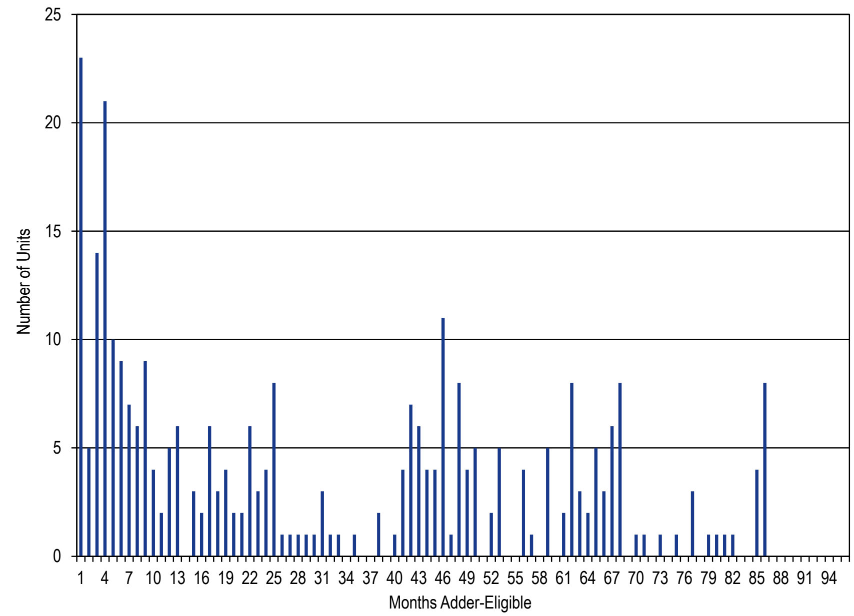
Table 2-28 shows the number of units that were eligible for an FMU or AU adder (Tier 1, Tier 2 or Tier 3) by the number of months they were eligible in 2012 and during the first three months of 2013. Of the 48 units eligible in at least one month during the first three months of 2013, 35 units (72.9 percent) were FMUs or AUs for all three months, and 7 units (14.6 percent) qualified in only one month of 2013.

Table 2-28 Frequently mitigated units and associated units total months eligible: 2012 and January through March, 2013

Months Adder-Eligible	FMU & AU Count	
	2012	2013
1	25	7
2	12	6
3	4	35
4	9	
5	2	
6	4	
7	14	
8	16	
9	15	
10	5	
11	2	
12	25	
Total	133	48

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, 2013, there have been 309 unique units that have qualified for an FMU adder in at least one month. Of these 309 units, no unit qualified for an adder in all potential months. Eight units qualified in 86 of the 87 possible months, and 110 of the 309 units (35.6 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, 2013



Market Performance: Load and LMP

The PJM system load and average 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 three months of 2013 increased by 5.8 percent from the first three months of 2012, from 86,329 MW to 91,337 MW.

PJM average day-ahead load, including DECs and up-to congestion transactions, in the first three months of 2013 increased by 11.1 percent from the first three months of 2012, from 129,258 MW to 143,585 MW.

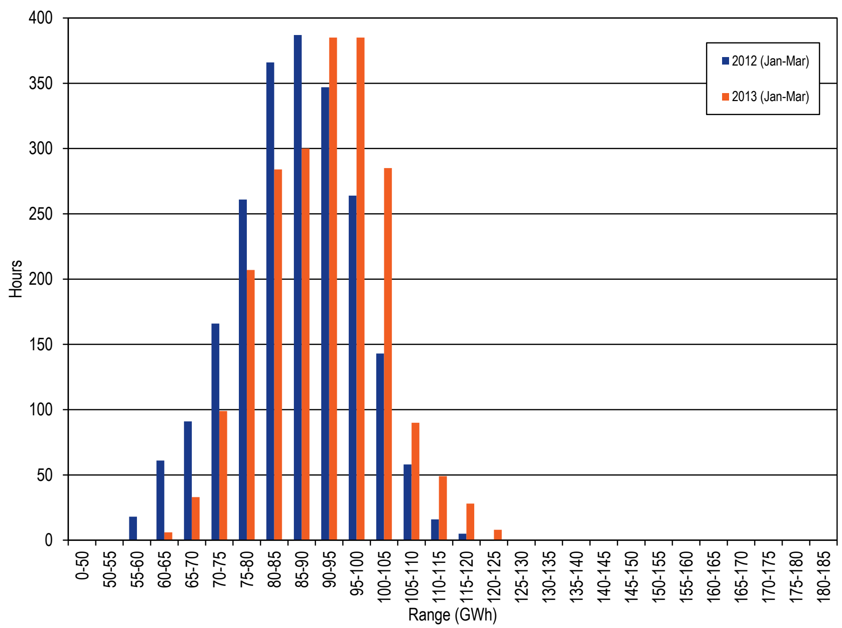
The day-ahead load growth was higher than the real-time load growth because of the continued growth of up-to congestion transactions. If the first three months of 2013 up-to congestion transactions had been held to the first three months of 2012 levels, the day-ahead load, including DECs and up-to congestion transactions, would have increased 3.4 percent instead of 11.1 percent and day-ahead load growth would have been lower than the real-time load growth.

Real-Time Load

PJM Real-Time Load Duration

Figure 2-7 shows the hourly distribution of PJM real-time load for the first three months of 2012 and 2013.[29]

Figure 2-7 PJM real-time accounting load: January through March of 2012 and 2013[30]



29 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.
30 Each range on the vertical axis includes the start value and excludes the end value.

PJM Real-Time, Average Load

Table 2-29 presents summary real-time load statistics for the first three months during the 16 year period 1998 to 2013. 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.[31]

Table 2-29 PJM real-time average hourly load: January through March of 1998 through 2013

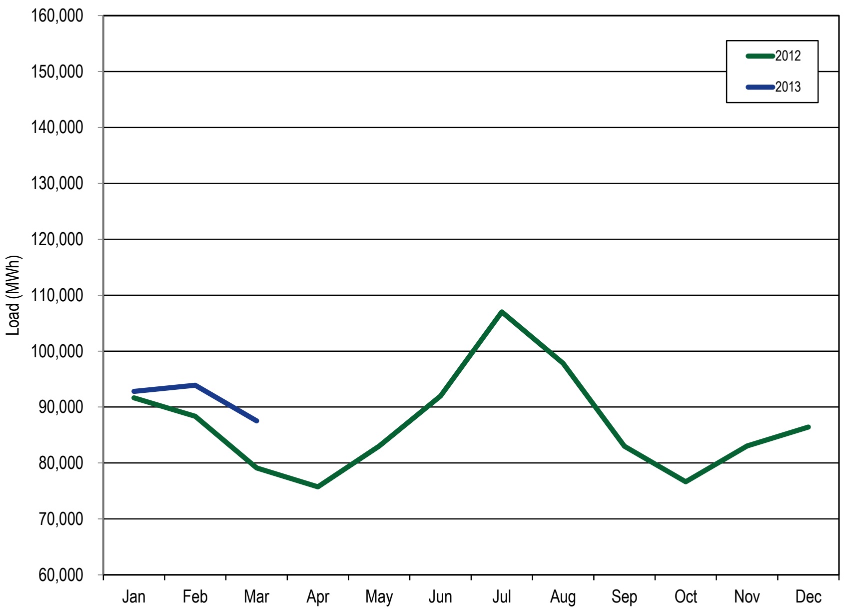
	PJM Real-Time Load (MWh)		Year-to-Year Change	
(Jan-Mar)	Average Load	Load Standard Deviation	Average Load	Load Standard Deviation
1998	28,019	3,762	NA	NA
1999	29,784	4,027	6.3%	7.0%
2000	30,367	4,624	2.0%	14.8%
2001	31,254	3,846	2.9%	(16.8%)
2002	29,968	4,083	(4.1%)	6.1%
2003	39,249	5,546	31.0%	35.8%
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	10,273	(0.1%)	(3.9%)
2012	86,329	10,947	6.6%	6.6%
2013	91,337	10,610	5.8%	(3.1%)

31 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.

PJM Real-Time, Monthly Average Load

Figure 2-8 compares the real-time, monthly average hourly loads in 2013 with those in 2012.

Figure 2-8 PJM real-time monthly average hourly load: January 2012 through March 2013



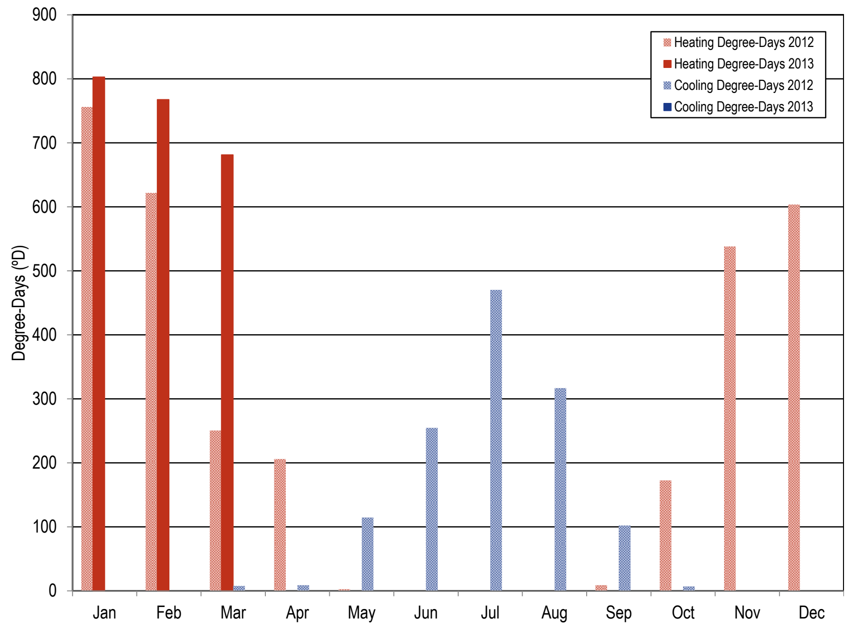
PJM real-time load is significantly affected by temperature. Figure 2-9 compares the total PJM monthly heating and cooling degree days in the first three months of 2013 with those in 2012.[32,33,34] The figure shows that in each of the first three months of 2013, the number of heating degree days was higher than in each of the first three months of 2012.

32 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degree F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings).

33 For additional information on the calculation of these weather variables, see PJM "Manual 19: Load Forecasting and Analysis," Revision 22 (February 28, 2013), Section 3, pp. 15-16. Load weighting using real-time zonal accounting load.

34 The weather stations that provided the basis for the analysis are ABE, ACY, AVP, BWI, CAK, CLE, CMH, CRW, CVG, DAY, DCA, ERI, EWR, FWA, IAD, ILG, IPT, ORD, ORF, PHL, PIT, RIC, ROA, TOL and WAL.

Figure 2-9 PJM Heating and Cooling Degree Days: January of 2012 through March of 2013[35]



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.

35 The version of this figure in the *2012 Quarterly State of the Market Report for PJM: January through September* reported the heating and cooling degree days using hourly totals by month. This figure properly reports the degree days using daily totals by month.

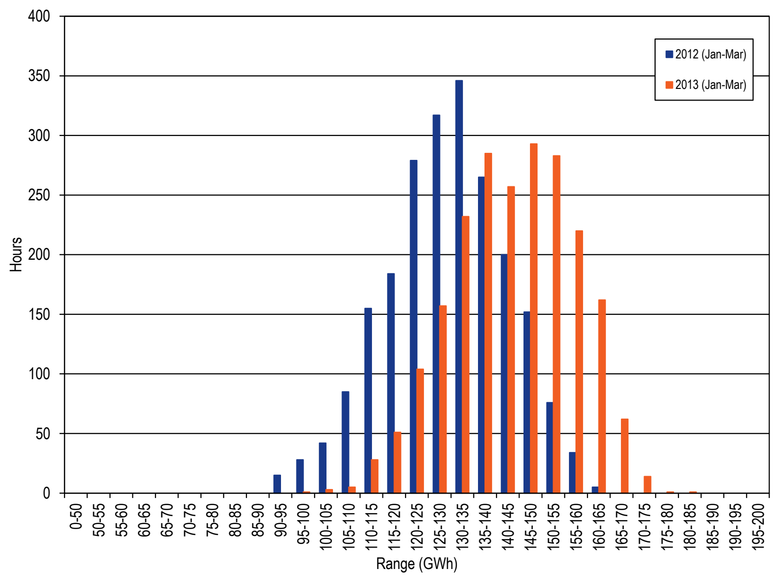
- **Up-to Congestion Transactions.** An up-to congestion transaction is a conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink.[36] In the PJM Day-Ahead Market, an up-to congestion transaction is evaluated and clears as a 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.[37]

PJM Day-Ahead Load Duration

Figure 2-10 shows the hourly distribution of PJM day-ahead load for the first three months of 2012 and 2013.

Figure 2-10 PJM day-ahead load: January through March of 2012 and 2013



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

37 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.

PJM Day-Ahead, Average Load

Table 2-30 presents summary day-ahead load statistics for the first three months of 13-year period 2001 to 2013.

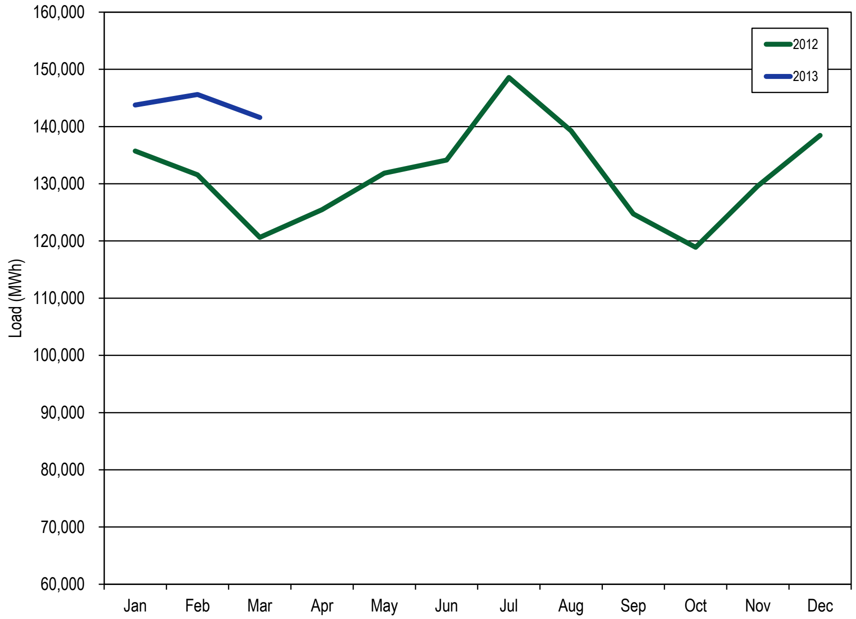
Table 2-30 PJM day-ahead average load: January through March of 2001 through 2013

	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	11,157	2,654	11,890	(4.4%)	136.7%	6.0%
2012	92,415	36,844	129,258	11,542	4,088	13,163	3.3%	108.9%	20.7%
2013	96,840	46,745	143,585	11,193	8,831	13,120	4.8%	26.9%	11.1%

PJM Day-Ahead, Monthly Average Load

Figure 2-11 compares the day-ahead, monthly average hourly loads of 2013 with those of 2012.

Figure 2-11 PJM day-ahead monthly average hourly load: January 2012 through March 2013



Real-Time and Day-Ahead Load

Table 2-31 presents summary statistics for the first three months of 2012 and 2013 day-ahead and real-time loads.

Table 2-31 Cleared day-ahead and real-time load (MWh): January through March of 2012 and 2013

		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	2012	83,557	895	7,962	36,844	129,258	86,329	42,929	(1,876)
	2013	88,395	943	7,502	46,745	143,585	91,337	52,248	(1,998)
Median	2012	84,076	886	7,852	36,671	129,802	86,486	43,316	(1,207)
	2013	89,132	873	7,188	46,492	144,317	91,993	52,325	(1,355)
Standard Deviation	2012	10,297	135	1,584	4,088	13,163	10,947	2,216	(3,457)
	2013	9,989	223	1,550	8,831	13,120	10,610	2,510	(7,871)
Peak Average	2012	90,231	963	8,501	37,274	136,970	92,984	43,986	(1,790)
	2013	95,586	1,004	8,190	46,276	151,056	98,579	52,477	(1,989)
Peak Median	2012	89,908	952	8,256	37,204	136,171	92,368	43,803	(1,657)
	2013	95,116	857	7,760	46,487	151,966	98,355	53,611	(635)
Peak Standard Deviation	2012	6,764	120	1,377	3,967	9,296	7,549	1,747	(3,597)
	2013	6,484	237	1,514	7,734	9,885	7,400	2,485	(6,763)
Off-Peak Average	2012	77,485	833	7,471	36,452	122,242	80,273	41,968	(1,955)
	2013	82,098	889	6,899	47,155	137,041	84,994	52,047	(2,006)
Off-Peak Median	2012	77,190	830	7,276	36,179	122,389	79,600	42,789	(666)
	2013	81,676	882	6,556	46,492	136,783	84,250	52,533	(515)
Off-Peak Standard Deviation	2012	9,138	117	1,602	4,159	12,207	10,005	2,202	(3,559)
	2013	8,087	195	1,311	9,675	12,068	8,777	3,291	(7,695)

Figure 2-12 shows the first three months average 2013 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 2-12 Day-ahead and real-time loads (Average hourly volumes): January through March of 2013

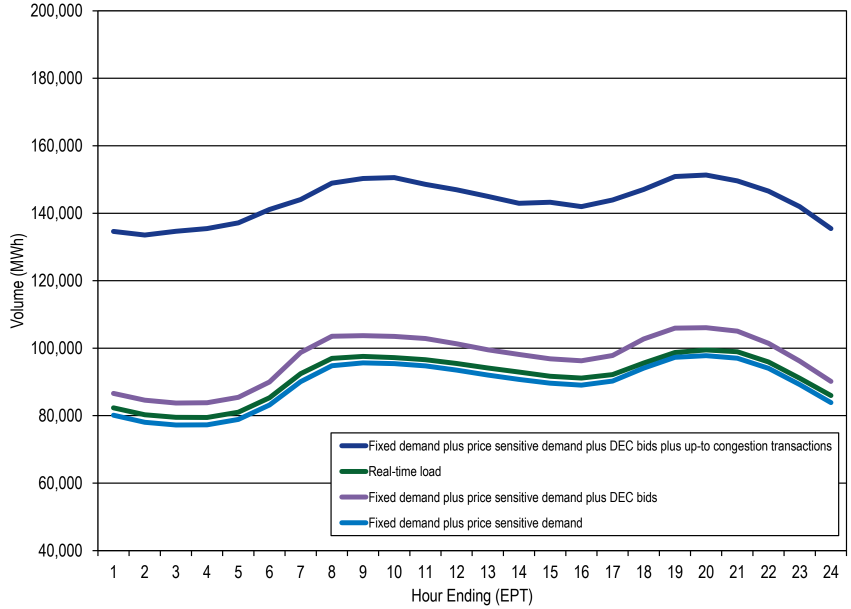


Figure 2-13 Difference between day-ahead and real-time loads (Average daily volumes): January 2012 through March of 2013

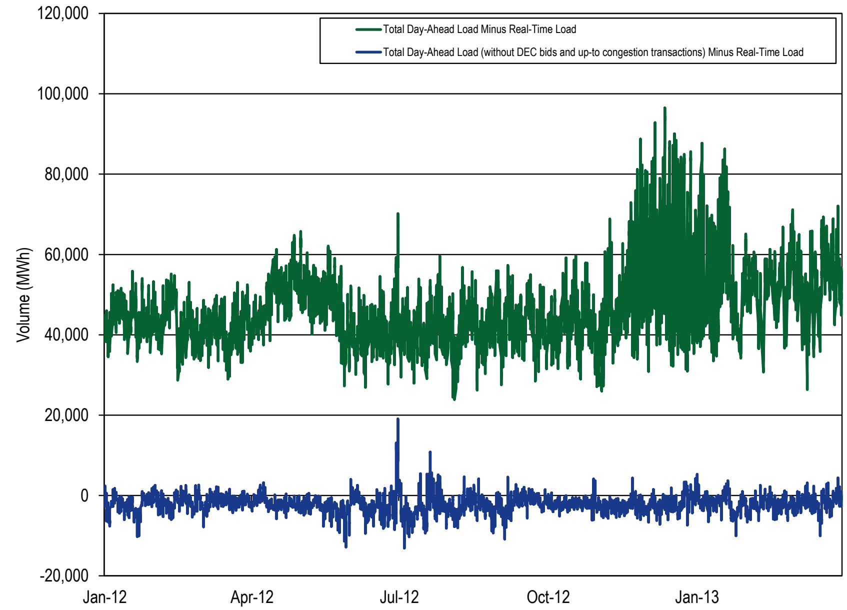


Figure 2-13 shows the difference between the day-ahead and real-time average daily loads in 2012 through the first three months of 2013.

Real-Time and Day-Ahead Generation

PJM average real-time generation in the first three months of 2013 increased by 5.3 percent from the first three months of 2012, from 88,068 MW to 92,776 MW.

PJM average day-ahead generation in the first three months of 2013, including INCs and up-to congestion transactions, increased by 11.4 percent from the first three months of 2012, from 132,178 MW to 147,246 MW.

The day-ahead generation growth was higher than the real-time generation growth because of the continued growth of up-to congestion transactions. If the first three months of 2013 up-to congestion transactions had been held to first three months of 2012 levels, the day-ahead generation, including INCs and up-to congestion transactions, would have increased 3.9 percent instead of 11.4 percent and day-ahead generation growth would have been lower than the real-time generation growth.

The real-time and day-ahead generation have been calculated have been calculated as net generation since 2003. What is termed negative generation, included in the average hourly generation for real time and day ahead, consists of power used by pumped storage hydro units when they are pumping and not generating, other units that draw station power when coming online and synchronized reserve units that use power while synchronized but not generating. These sources of negative generation are actually load on the system, although they are not currently included in the average hourly real-time and day-ahead load.

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:[38]

- **Self-Scheduled.** Offer to supply a fixed block of MWh that must run from a specific unit, including a minimum amount of MWh that must run from a specific unit that also has a dispatchable component above the minimum.[39]
- **Generator Offer.** Offer to supply a schedule of MWh and the corresponding offer prices from a specific unit.
- **Increment Offer (INC).** Financial offer to supply specified MWh and the 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.[40] 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 2-32 presents summary real-time generation statistics for the first three months of the 11-year period from 2003 through 2013.

Table 2-32 PJM real-time average hourly generation: January through March of 2003 through 2013

	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	10,116	2.2%	(21.0%)
2012	88,068	11,177	5.5%	10.5%
2013	92,776	10,030	5.3%	(10.3%)

Table 2-33 presents summary day-ahead generation statistics for the first three months of the 11-year period from 2003 through 2013.

38 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 *2012 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market."
39 The definition of self-scheduled is based on the PJM "eMKT User Guide" (October, 2012), pp. 41-44.
40 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 2-33 PJM day-ahead average hourly generation: January through March of 2003 through 2013

	PJM Day-Ahead Generation (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
(Jan-Mar)	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	11,463	2,654	12,200	(1.7%)	136.7%	8.4%
2012	95,334	36,844	132,178	12,066	4,088	13,701	2.9%	108.9%	19.8%
2013	100,502	46,745	147,246	11,224	8,831	13,054	5.4%	26.9%	11.4%

Table 2-34 presents summary statistics for the first three months of 2012 and 2013 for day-ahead and real-time generation.

Table 2-34 Day-ahead and real-time generation (MWh): January through March of 2012 and 2013

		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	2012	88,942	6,392	36,844	132,178	88,068	874	44,110
	2013	94,829	5,673	46,745	147,246	92,776	2,053	54,471
Median	2012	89,373	6,345	36,671	132,597	88,079	1,294	44,518
	2013	95,320	5,702	46,492	148,031	93,346	1,974	54,685
Standard Deviation	2012	11,883	773	4,088	13,701	11,177	706	2,524
	2013	10,944	680	8,831	13,054	10,030	913	3,024
Peak Average	2012	96,169	6,557	37,274	140,000	94,441	1,728	45,559
	2013	102,331	6,085	46,276	154,692	99,495	2,835	55,196
Peak Median	2012	95,687	6,497	37,204	139,084	94,019	1,668	45,065
	2013	101,557	6,096	46,487	155,453	99,374	2,183	56,079
Peak Standard Deviation	2012	7,975	595	3,967	9,825	8,066	(90)	1,759
	2013	7,445	508	7,734	9,731	7,131	313	2,599
Off-Peak Average	2012	82,367	6,242	36,452	125,061	82,271	96	42,790
	2013	88,258	5,313	47,155	140,726	86,891	1,368	53,835
Off-Peak Median	2012	82,252	6,106	36,179	125,297	82,113	139	43,184
	2013	87,617	5,210	46,492	140,418	86,261	1,356	54,157
Off-Peak Standard Deviation	2012	11,006	879	4,159	12,823	10,435	571	2,388
	2013	9,147	602	9,675	12,072	8,367	780	3,705

Figure 2-14 shows the first three months average 2013 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.[41]

Figure 2-14 Day-ahead and real-time generation (Average hourly volumes): January through March of 2013

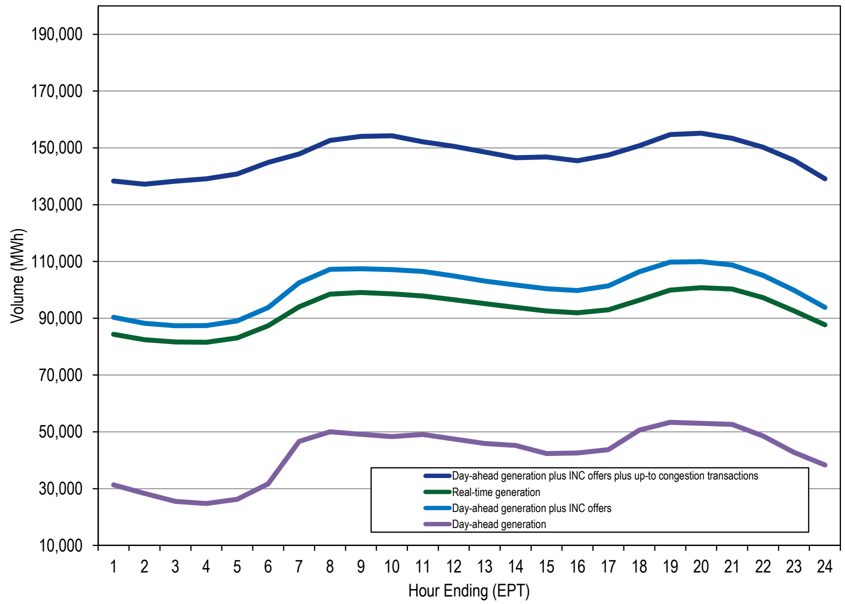


Figure 2-15 shows the difference between the day-ahead and real-time average daily generation in 2012 through the first three months of 2013.

Figure 2-15 Difference between day-ahead and real-time generation (Average daily volumes): January 2012 through March of 2013

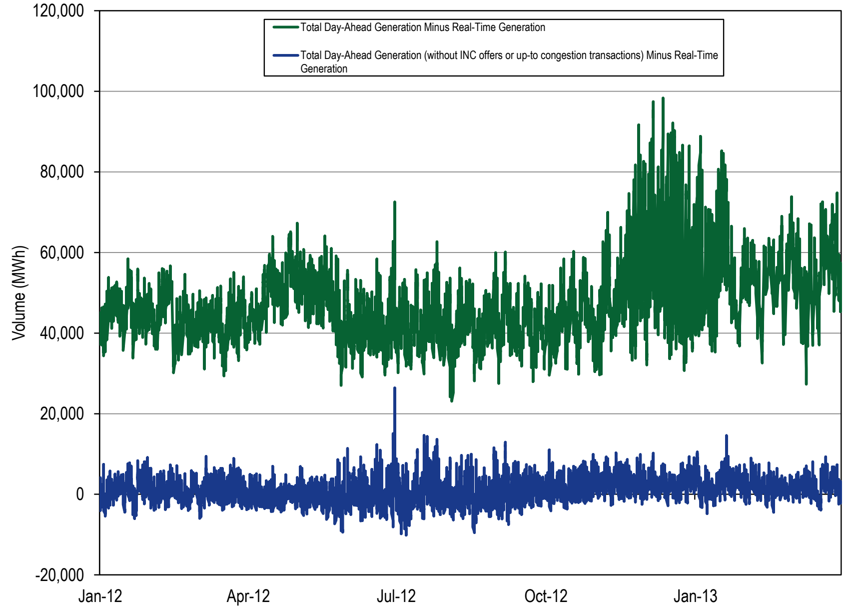


Figure 2-16 and Table 2-35 show the total difference between the PJM real-time generation and real-time load by zone in the first three months of 2013. Figure 2-16 is color coded on a scale where red shades represent zones that have less generation than load and green shades represent zones that have more generation than load, with darker shades meaning greater amounts of net generation or load. For example, the Pepco Control Zone has less generation than load, while the PENELEC Control Zone has more generation than load.

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

Figure 2-16 PJM real-time generation less real-time load by zone (GWh): January through March of 2013

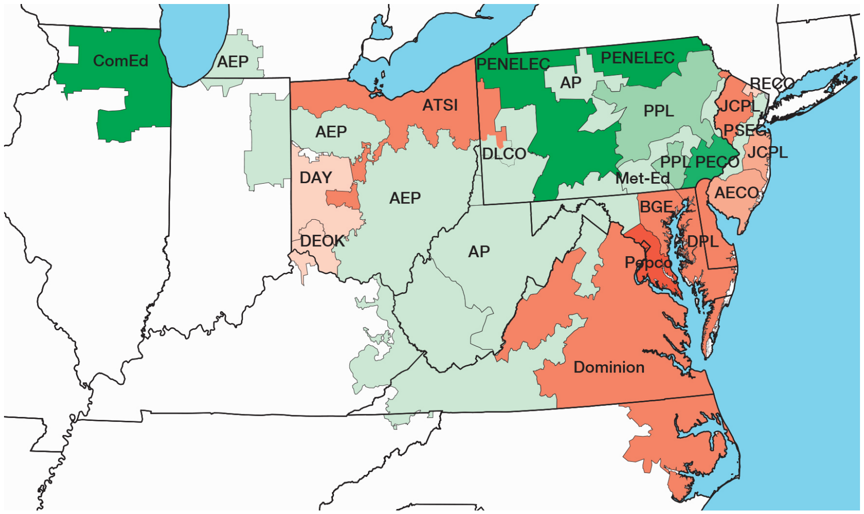


Table 2-35 PJM real-time generation less real-time load by zone (GWh): January through March of 2012 and 2013

	Zonal Generation and Load (GWh)					
	2012 (Jan-Mar)			2013 (Jan-Mar)		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	315.7	2,375.2	(2,059.5)	400.5	2,472.5	(2,072.0)
AEP	35,530.0	33,662.8	1,867.3	35,431.1	34,699.0	732.1
AP	11,160.2	11,995.8	(835.6)	14,090.8	12,833.1	1,257.7
ATSI	14,429.9	16,614.2	(2,184.3)	14,092.2	17,074.0	(2,981.8)
BGE	3,786.0	8,014.2	(4,228.2)	4,826.2	8,298.0	(3,471.8)
ComEd	32,497.1	23,604.9	8,892.2	31,380.5	24,356.2	7,024.2
DAY	3,827.8	4,189.5	(361.8)	4,026.8	4,317.1	(290.3)
DEOK	4,763.8	6,431.8	(1,668.0)	6,615.6	6,730.9	(115.2)
Dominion	20,084.5	22,326.9	(2,242.4)	20,993.3	24,333.0	(3,339.7)
DPL	1,710.4	4,427.9	(2,717.5)	1,602.2	4,838.0	(3,235.8)
DLCO	4,786.4	3,579.5	1,206.9	4,841.3	3,638.3	1,203.0
JCPL	2,782.6	5,275.0	(2,492.4)	1,881.6	5,527.1	(3,645.6)
Met-Ed	5,348.7	3,757.1	1,591.6	5,427.8	3,956.2	1,471.6
PECO	15,492.3	9,558.5	5,933.8	15,004.3	10,069.0	4,935.3
PENELEC	9,473.4	4,408.1	5,065.3	11,825.4	4,637.0	7,188.4
Pepco	1,668.5	7,373.3	(5,704.8)	2,161.9	7,625.7	(5,463.8)
PPL	13,235.9	10,364.3	2,871.6	13,815.7	10,996.3	2,819.4
PSEG	11,360.4	10,153.3	1,207.1	11,885.4	10,440.5	1,444.9
RECO	0.0	343.6	(343.6)	0.0	353.8	(353.8)

Locational Marginal Price (LMP)

The conduct of individual market entities within a market structure is reflected in market prices.[42] PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses and local price differences caused by congestion. Real-Time and Day-Ahead Energy Market load-weighted prices were 19.9 percent and 18.3 percent higher in the first three months of 2013 than in the first three months of 2012 as a result of higher fuel costs and higher demand.[43] Natural

42 See the *2012 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.

43 There was an average increase of 7.1 heating degree days and an average reduction of 0.1 cooling degree days in the first three months of 2013 compared to the first three months of 2012 which meant overall increased demand.

gas prices were higher, particularly in eastern zones, while coal prices were constant or decreased. The fuel-cost-adjusted, load weighted LMP in the first three months of 2013 shows that the mix of fuel types and fuel costs resulted in slightly higher prices than would have occurred if fuel prices had remained at the same levels as in the first three months of 2012.

PJM Real-Time Energy Market prices increased in the first three months of 2013 compared to the first three months of 2012. The system average LMP was 19.6 percent higher in the first three months of 2013 than in the first three months of 2012, $36.33 per MWh versus $30.38 per MWh. The load-weighted average LMP was 19.9 percent higher in the first three months of 2013 than in the first three months of 2012, $37.41 per MWh versus $31.21 per MWh.

PJM Day-Ahead Energy Market prices increased in the first three months of 2013 compared to the first three months of 2012. The system average LMP was 18.3 percent higher in the first three months of 2013 than in the first three months of 2012, $36.46 per MWh versus $30.82 per MWh. The load-weighted average LMP was 18.3 percent higher in the first three months of 2013 than in the first three months of 2012, $37.26 per MWh versus $31.51 per MWh.[44]

Real-Time LMP

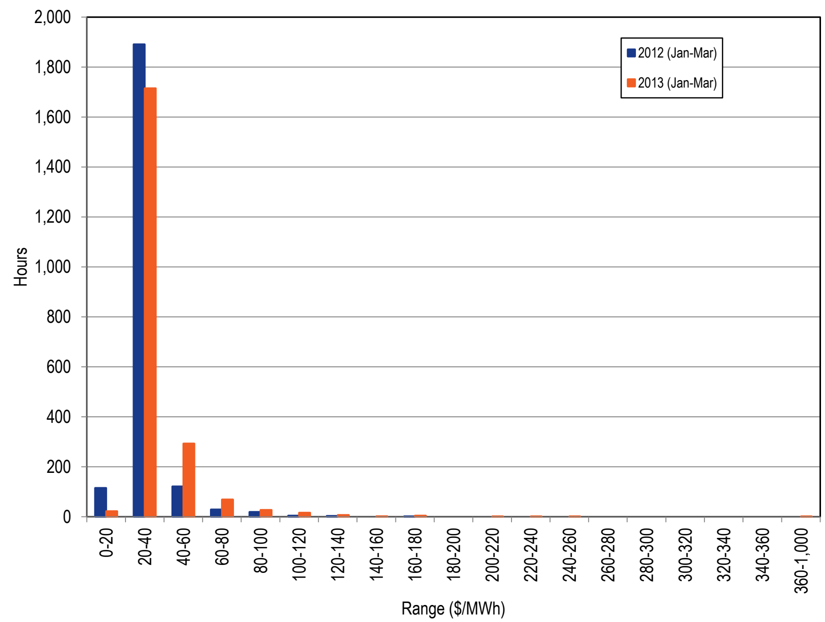
Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[45] This section discusses the real-time average LMP and the real-time load weighted average LMP. Average LMP is the unweighted average LMP.

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 2-17 shows the hourly distribution of PJM real-time average LMP for the first three months of 2012 and 2013.

Figure 2-17 Average LMP for the PJM Real-Time Energy Market: January through March of 2012 and 2013



44 Tables reporting zonal and jurisdictional load and prices are in the *2012 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

45 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 2-36 shows the PJM real-time, average LMP for the first three months of the 16-year period 1998 to 2013.[46]

Table 2-36 PJM real-time, average LMP (Dollars per MWh): January through March of 1998 through 2013

	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%)
2013	$36.33	$32.29	$18.47	19.6%	12.1%	58.9%

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 2-37 shows the PJM real-time, load-weighted, average LMP for the first three months of the 16-year period 1998 to 2013.

46 The system 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.

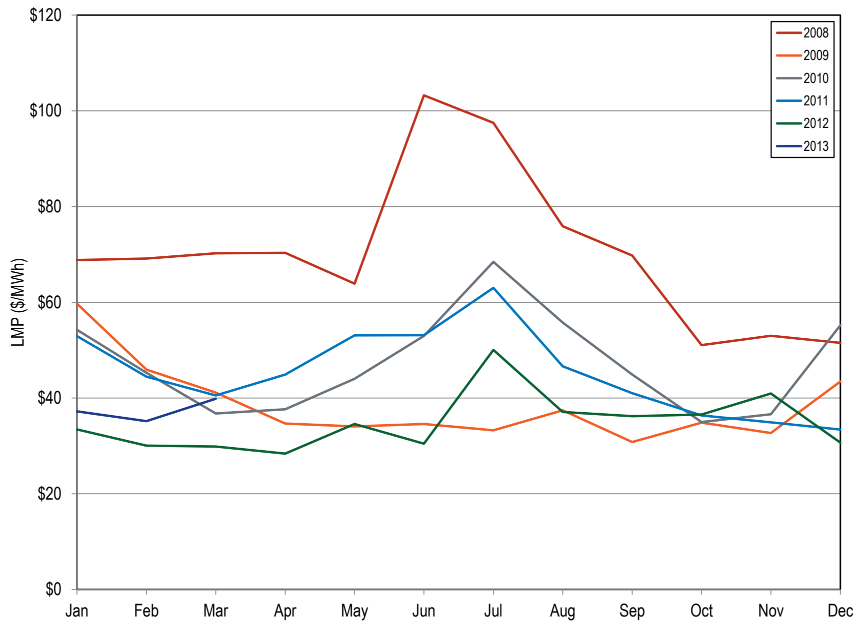
Table 2-37 PJM real-time, load-weighted, average LMP (Dollars per MWh): January through March of 1998 through 2013

	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%)
2013	$37.41	$32.79	$19.90	19.9%	12.1%	65.7%

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

Figure 2-18 shows the PJM real-time, monthly, load-weighted LMP from 2008 through the first three months of 2013.

Figure 2-18 PJM real-time, monthly, load-weighted, average LMP: January 2008 through March of 2013



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. Natural gas, especially in the eastern part of PJM increased in price in the first three months of 2013. Comparing prices in the first three months of 2013 to prices in 2012, the price of Northern Appalachian coal was 2.1 percent lower; the price of Central Appalachian coal was 3.8 percent higher; the price of Powder River Basin coal was 16.5 percent higher; the price of eastern natural gas was 72.2 percent higher; and the price of western natural gas was 28.0 percent higher. Figure 2-19 shows monthly average spot fuel prices for 2012 and the first three months of 2013.[47] Natural gas prices were above coal prices in the first three months of 2013, with prices above $10/MMBtu for some days. Coal prices decreased during the first three months of 2013 but remained relatively flat in comparison to 2012.

Figure 2-19 Spot average fuel price comparison: 2012 and January through March 2013 ($/MMBtu)

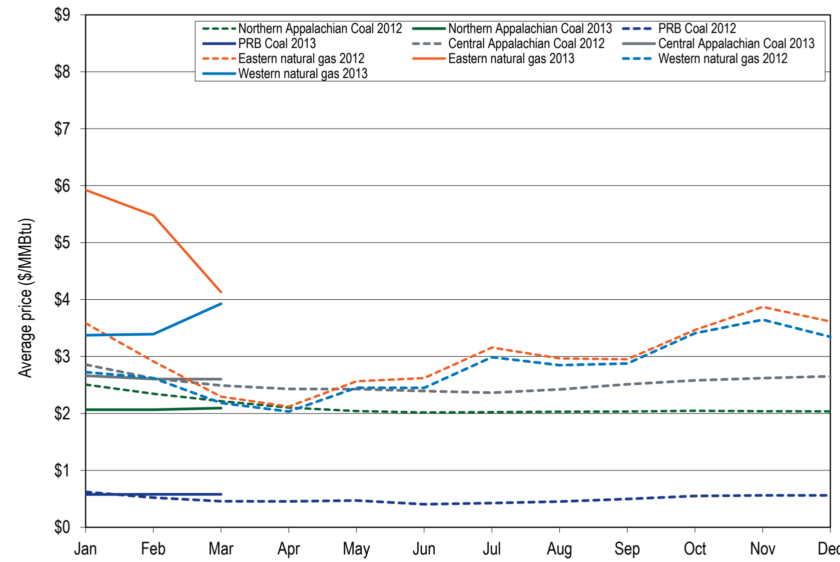


Figure 2-20 shows the average cost of generation, comparing the cost of energy generated by a coal plant, a combined cycle, and a combustion turbine in dollars per MWh. The cost of a new entrant combined cycle was below the cost of a new entrant coal plant for the first three months of 2013. The average spot fuel cost of a new entrant combined cycle unit was $36.83/MWh, higher than the spot fuel cost of a new entrant coal plant, $19.19/MWh, in 2012.

47 Eastern natural gas and Western natural gas 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.

In the market, new combined cycles are competing with older coal plants. Most coal plants in PJM are 20 years or older, with heat rates greater than a new coal plant. Using average heat rates for existing sub-critical coal units, as well as delivery adders and variable operations and maintenance adders, the average cost of a sub-critical coal unit in PJM in the first three months of 2013 was $31.06, compared to $38.40 for a new entrant combined cycle in the eastern zones. In March, due to lower natural gas prices and slightly higher coal prices, the cost of a new entrant combined cycle unit was $30.93, or below that of a sub-critical coal unit in PJM, at $31.26.

Figure 2-20 Average spot fuel cost of generation of CP, CT, CC, and PJM average heat rate sub-critical coal plant: 2012 and January through March 2013 ($/MWh)

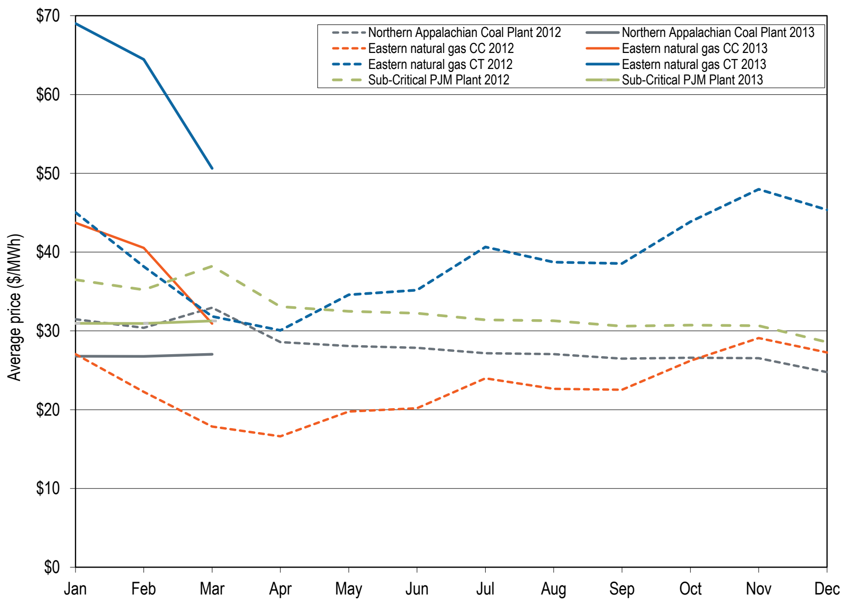


Table 2-38 compares the first three months of 2013 PJM real-time fuel cost adjusted, load weighted, average LMP to the first three months of 2012 load-weighted, average LMP. The fuel cost adjusted, load weighted, average LMP for the first three months of 2013 was 9.8 percent lower than the load weighted, average LMP for the first three months of 2013. The real-time, fuel cost adjusted, load weighted, average LMP for the first three months of 2013 was 8.1 percent higher than the load weighted LMP for the first three months of 2012. If fuel costs in 2013 had been the same as in 2012, holding everything else constant, the 2013 load weighted LMP would have been lower, $33.74 per MWh instead of the observed $37.41 per MWh. The mix of fuel types and fuel costs in 2013 resulted in slightly higher prices in 2013 than would have occurred if fuel prices had remained at their 2012 levels.

Table 2-38 PJM real-time annual, fuel-cost-adjusted, load-weighted average LMP (Dollars per MWh): Year-over-year method

	2013 Load-Weighted LMP	2013 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$37.41	$33.74	(9.8%)
	2012 Load-Weighted LMP	2013 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$31.21	$33.74	8.1%
	2012 Load-Weighted LMP	2013 Load-Weighted LMP	Change
Average	$31.21	$37.41	19.9%

Components of Real-Time, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, economic (least-cost) dispatch (SCED) in which marginal units determine system LMPs, based on their offers and five-minute-ahead forecast of the system conditions. Those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder and the 10 percent cost adder. As a result, it is possible to decompose PJM system's load-weighted LMP using the components of unit offers and sensitivity factors.

The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal. Cost offers of marginal units are broken into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs were calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, fuel-specific emission rates for NO_x and unit-specific emission rates for SO_2.

The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland and New Jersey.[48]

Prior to the implementation of scarcity pricing on October 1, 2012, LMPs calculated based on SCED were modified ex-post to account for realized system conditions. This is sometimes referred to as an ex-post LMP calculation. The extent to which the ex-post LMP in a five-minute interval deviated from the LMP calculated by SCED (ex-ante LMP) reflected the change in system conditions between the time when the dispatch was solved, and the end of the five-minute interval. The contribution of this deviation to real-time LMPs is shown as the LPA-SCED differential. Starting with the October 1, 2012, implementation of scarcity pricing, PJM eliminated ex-post pricing and relies entirely on ex-ante pricing. After October 1, 2012, real-time LMPs are based solely on the interval's most recent SCED solution.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes energy and ancillary services. Occasionally, generators providing energy have to be redispatched lower to increase reserves for meeting ancillary service requirements. The cooptimization of energy and reserves takes into account the lost opportunity cost of lowered generation and the incremental cost to maintain reserves, which are reflected in higher LMPs. The cost of substituting energy for reserve and regulation is shown as Ancillary Service Redispatch Cost. Occasionally, an abrupt loss of generation triggers the need for substituting energy for reserve and consequently higher prices.

The components of LMP are shown in Table 2-39, including markup using unadjusted cost offers.[49] (Numbers in parentheses in the table are negative.) Table 2-39 shows that for the first three months of 2013, 53.7 percent of the load-weighted LMP was the result of coal costs, 30.3 percent was the result of gas costs and 0.52 percent was the result of the cost of emission allowances. Markup was -$2.69 per MWh. In the first three months of 2012, 66.7 percent of the load-weighted LMP was the result of coal costs, 20.9 percent was the result of gas costs and 0.7 percent was the result of the cost of emission allowances. Markup was -$2.55. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP rather than all of the components of the offers of units burning that fuel.

48 New Jersey withdrew from RGGI, effective January 1, 2012.
49 These components are explained in the *Technical Reference for PJM Markets*, Section 7 "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table 2-39 Components of PJM real-time (Unadjusted), annual, load-weighted, average LMP: January through March 2013 and 2012

	2012 (Jan-Mar)		2013 (Jan-Mar)	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$20.83	66.7%	$20.07	53.7%
Gas	$6.51	20.9%	$11.34	30.3%
Ten Percent Addder	$3.36	10.8%	$3.77	10.1%
VOM	$2.34	7.5%	$2.29	6.1%
NA	$0.23	0.7%	$0.68	1.8%
LPA Rounding Difference	$0.22	0.7%	$0.65	1.7%
Ancillary Service Redispatch Cost	$0.00	0.0%	$0.38	1.0%
FMU Adder	$0.04	0.1%	$0.37	1.0%
Oil	$0.28	0.9%	$0.30	0.8%
Increase Generation Adder	($0.06)	(0.2%)	$0.15	0.4%
CO_2 Cost	$0.06	0.2%	$0.09	0.2%
NO_x Cost	$0.12	0.4%	$0.09	0.2%
SO_2 Cost	$0.02	0.1%	$0.01	0.0%
Market-to-Market Adder	$0.05	0.2%	$0.00	0.0%
Wind	($0.07)	(0.2%)	$0.00	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%
Other	$0.00	0.0%	$0.00	0.0%
Decrease Generation Adder	($0.17)	(0.5%)	($0.10)	(0.3%)
LPA-SCED Differential	($0.01)	(0.0%)	$0.00	0.0%
Markup	($2.55)	(8.2%)	($2.69)	(7.2%)
Total	$31.21	100.0%	$37.41	100.0%

All generating units, including coal units, are allowed to include a ten percent adder in their cost offer. The 10 percent adder was included in the definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions.

In order to accurately assess the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach (Table 2-39 and Table 2-43), markup is simply the difference between the price offer and the cost offer. In the second approach

(Table 2-40 and Table 2-44), the 10 percent markup is removed from the cost offers of coal units. Coal units do not face the same cost uncertainty as gas-fired CTs. Actual participant behavior support this view, as the owners of coal units, facing competition, typically remove the 10 percent adder from their actual offers. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the 10 percent adder in the cost offer.

The components of LMP are shown in Table 2-40, including markup using adjusted cost offers.

Table 2-40 Components of PJM real-time (Adjusted), annual, load-weighted, average LMP: January through March 2013 and 2012

	2012 (Jan-Mar)		2013 (Jan-Mar)	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$21.01	67.3%	$20.31	54.3%
Gas	$6.51	20.9%	$11.35	30.3%
VOM	$2.36	7.5%	$2.31	6.2%
Ten Percent Adder	$1.12	3.6%	$1.88	5.0%
NA	$0.23	0.7%	$0.65	1.7%
LPA Rounding Difference	$0.22	0.7%	$0.65	1.7%
Ancillary Service Redispatch Cost	$0.00	0.0%	$0.38	1.0%
Oil	$0.28	0.9%	$0.30	0.8%
FMU Adder	$0.04	0.1%	$0.27	0.7%
Increase Generation Adder	($0.06)	(0.2%)	$0.15	0.4%
CO_2 Cost	$0.06	0.2%	$0.09	0.3%
NO_x Cost	$0.12	0.4%	$0.09	0.2%
SO_2 Cost	$0.02	0.1%	$0.01	0.0%
Market-to-Market Adder	$0.05	0.2%	$0.00	0.0%
Wind	($0.07)	(0.2%)	$0.00	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%
Other	$0.00	0.0%	$0.00	0.0%
Decrease Generation Adder	($0.17)	(0.5%)	($0.10)	(0.3%)
LPA-SCED Differential	($0.01)	(0.0%)	$0.00	0.0%
Markup	($0.51)	(1.6%)	($0.95)	(2.5%)
Total	$31.21	100.0%	$37.41	100.0%

Day-Ahead LMP

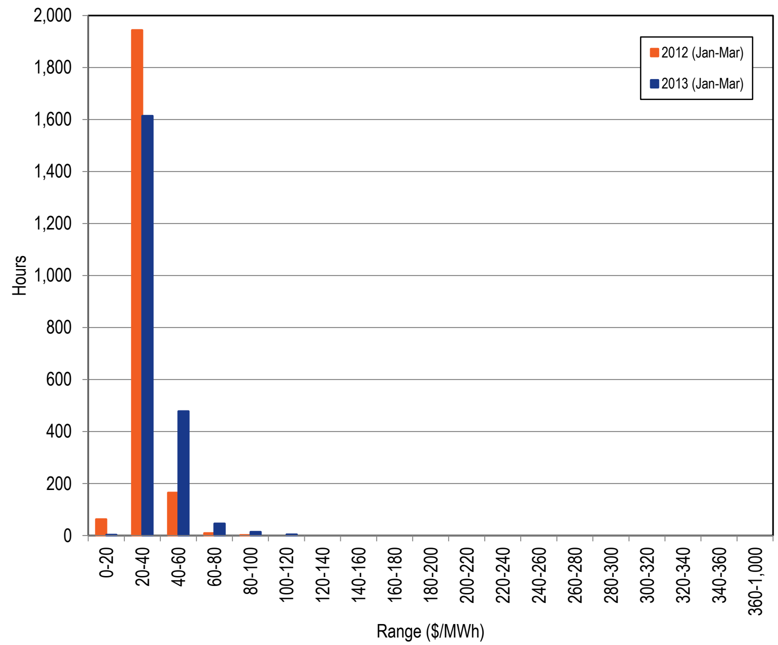
Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[50] This section discusses the day-ahead average LMP and the day-ahead load weighted average LMP. Average LMP is the unweighted average LMP.

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 2-21 shows the hourly distribution of PJM day-ahead average LMP for the first three months of 2012 and 2013.

Figure 2-21 Price for the PJM Day-Ahead Energy Market: January through March of 2012 and 2013



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

PJM Day-Ahead, Average LMP

Table 2-41 shows the PJM day-ahead, average LMP for the first three months of the 13-year period 2001 to 2013.

Table 2-41 PJM day-ahead, average LMP (Dollars per MWh): January through March of 2001 through 2013

	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	$30.82	$30.04	$6.63	(32.4%)	(26.9%)	(60.6%)
2013	$36.46	$34.45	$9.78	18.3%	14.7%	47.5%

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 2-42 shows the PJM day-ahead, load-weighted, average LMP for the first three months of the 13-year period 2001 to 2013.

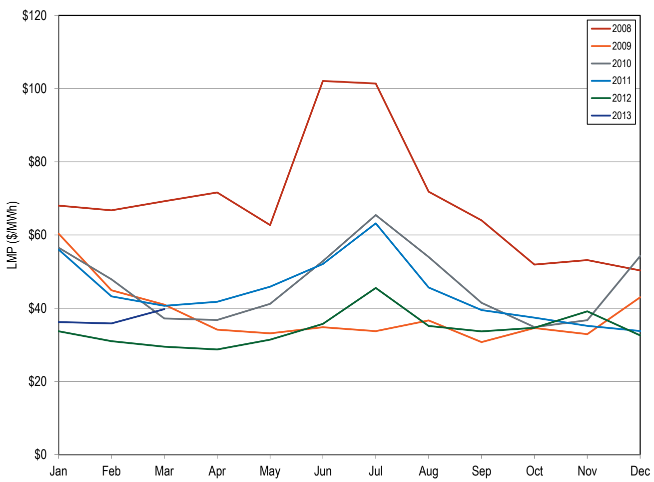
Table 2-42 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through March of 2001 through 2013

	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%)
2013	$37.26	$35.02	$10.26	18.3%	15.0%	50.3%

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

Figure 2-22 shows the PJM day-ahead, monthly, load-weighted LMP from 2008 through the first three months of 2013.

Figure 2-22 Day-ahead, monthly, load-weighted, average LMP: January 2008 through March of 2013



Components of Day-Ahead, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. For physical units, those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder, Day-Ahead Scheduling Reserve (DASR) adder and the 10 percent cost offer adder. INC offers, DEC bids and up-to congestion transactions are dispatchable injections and withdrawals in the Day Ahead market. To the extent that INCs, DECs or up-to congestion transactions are the marginal resource, they either directly or indirectly set price via their offers and bids. Using identified marginal resource offers and the components of the offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal. Day-Ahead Scheduling Reserve (DASR) lost opportunity cost (LOC) and DASR offer adders are the calculated contribution to LMP when redispatch of resources is needed in order to satisfy DASR requirements. Cost offers of marginal units are broken into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs were calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, fuel-specific emission rates for NO_x and unit-specific emission rates for SO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland and New Jersey.[51]

Table 2-43 shows the components of the PJM day ahead, annual, load-weighted average LMP.

51 New Jersey withdrew from RGGI, effective January 1, 2012.

Table 2-43 Components of PJM day-ahead, (unadjusted) annual, load-weighted, average LMP (Dollars per MWh): January through March 2012 and 2013[52]

	2012 (Jan - Mar)		2013 (Jan - Mar)	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$14.73	46.8%	$15.47	41.5%
Gas	$5.77	18.3%	$5.57	14.9%
DEC	$4.02	12.8%	$7.20	19.3%
INC	$3.33	10.6%	$3.23	8.7%
Up-to Congestion Transaction	$2.05	6.5%	$2.45	6.6%
10% Cost Adder	$1.50	4.8%	$1.68	4.5%
VOM	$1.12	3.6%	$3.07	8.2%
Dispatchable Transaction	$0.88	2.8%	$0.18	0.5%
Price Sensitive Demand	$0.55	1.8%	$0.43	1.2%
FMU Adder	$0.13	0.4%	$0.01	0.0%
CO_2	$0.08	0.3%	$0.06	0.2%
NO_x	$0.03	0.1%	$0.07	0.2%
Oil	$0.02	0.1%	$0.01	0.0%
SO_2	$0.00	0.0%	$0.00	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%
DASR LOC Adder	($0.00)	(0.0%)	$0.00	0.0%
DASR Offer Adder	($2.70)	(8.6%)	($2.74)	(7.4%)
Markup	$0.00	0.0%	$0.13	0.4%
NA	($0.00)	(0.0%)	$0.43	1.2%
Total	$31.51	100.0%	$37.26	100.0%

Table 2-44 shows the components of the PJM day ahead, annual, load-weighted average LMP.

52 The NA in 2013 is $0.43. It is caused by bad savecase input files for March 5, 2013.

Table 2-44 Components of PJM day-ahead, (adjusted) annual, load-weighted, average LMP (Dollars per MWh): January through March 2012 and 2013

	2012 (Jan - Mar)		2013 (Jan - Mar)	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$14.73	46.8%	$15.47	41.5%
Gas	$5.77	18.3%	$5.57	14.9%
DEC	$4.02	12.8%	$7.20	19.3%
INC	$3.33	10.6%	$3.23	8.7%
Up-to Congestion Transaction	$1.50	4.8%	$1.68	4.5%
VOM	$1.12	3.6%	$3.07	8.2%
10% Cost Adder	$0.88	2.8%	$0.18	0.5%
Dispatchable Transaction	$0.87	2.7%	$1.60	4.3%
Price Sensitive Demand	$0.55	1.8%	$0.43	1.2%
FMU Adder	$0.13	0.4%	$0.01	0.0%
CO_2	$0.08	0.3%	$0.06	0.2%
NO_x	$0.03	0.1%	$0.07	0.2%
Oil	$0.02	0.1%	$0.01	0.0%
SO_2	$0.00	0.0%	$0.00	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%
DASR LOC Adder	($0.00)	(0.0%)	$0.00	0.0%
DASR Offer Adder	($1.51)	(4.8%)	($1.89)	(5.1%)
Markup	$0.00	0.0%	$0.13	0.4%
NA	($0.00)	(0.0%)	$0.43	1.2%
Total	$31.51	100.0%	$37.26	100.0%

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.[53]

53 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. Internal up-to congestion transactions may source or sink at any of the eligible hubs, transmission zones, aggregates, or single buses for which LMP is calculated. For a complete list of eligible locations for up-to congestion source and sink transactions see the following link from the PJM website: <http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>.

Figure 2-23 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 2013.

Figure 2-23 PJM day-ahead aggregate supply curves: 2013 example day

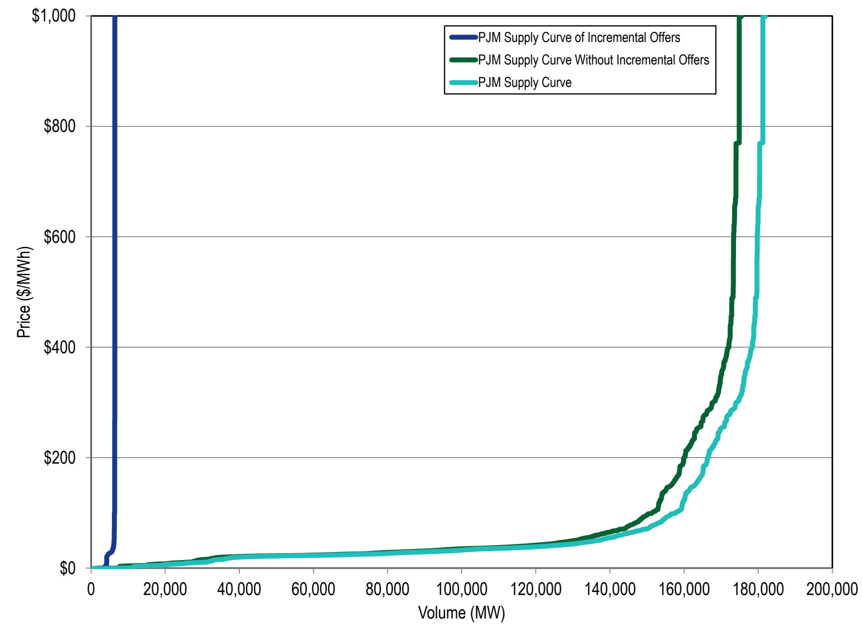


Table 2-45 shows the average volume of trading in increment offers and decrement bids per hour and the average total MW values of all bids per hour for 2012 through the first three months of 2013. Table 2-46 shows the average volume of up-to congestion transactions per hour and the average total MW values of all bids per hour for 2012 through the first three months of 2013. In the first three months of 2013, the average submitted and cleared increment bid MW decreased 31.7 and 11.1 percent, and the average submitted and cleared decrement bid MW decreased 22.6 and 5.6 percent, compared to the first three months of 2012. In the first three months of 2013, average up-to congestion submitted MW increased 47.5 percent and cleared MW increased 26.8 percent, compared to the first three months of 2012. The increase in up-to congestion transactions displaced increment and decrement transactions.

Table 2-45 Hourly average volume of cleared and submitted INCs, DECs by month: January 2012 through March of 2013

		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
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	Apr	6,355	9,368	87	298	7,812	10,811	105	329
2012	May	6,224	8,447	80	271	8,785	11,141	109	316
2012	Jun	6,415	8,360	79	234	9,030	11,124	97	270
2012	Jul	6,485	8,270	81	285	8,981	11,121	112	349
2012	Aug	5,809	7,873	74	291	8,471	10,507	100	320
2012	Sep	5,274	7,509	78	313	8,192	10,814	109	381
2012	Oct	5,231	6,953	82	275	8,901	11,526	110	361
2012	Nov	5,423	6,944	67	190	8,678	11,758	102	289
2012	Dec	5,622	7,090	69	183	8,456	10,007	84	207
2012	Annual	6,001	8,428	81	311	8,431	11,089	105	343
2013	Jan	5,682	7,271	80	195	7,944	9,653	81	211
2013	Feb	5,949	7,246	61	130	7,689	8,942	75	165
2013	Mar	5,414	6,192	50	94	6,890	7,907	65	140
2013	Annual	5,682	6,903	63	140	7,507	8,834	74	172

Table 2-46 Hourly average of cleared and submitted up-to congestion bids by month: January 2012 through March 2013

		Up-to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
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	Apr	43,777	120,955	1,013	2,519
2012	May	43,468	119,374	1,052	2,541
2012	Jun	35,052	101,065	915	2,193
2012	Jul	35,179	118,294	981	2,710
2012	Aug	35,515	122,458	986	2,787
2012	Sep	35,199	112,731	946	2,801
2012	Oct	35,365	106,819	990	2,692
2012	Nov	40,499	143,853	1,329	3,934
2012	Dec	45,536	176,660	1,681	5,145
2012	Annual	38,343	119,744	1,033	2,801
2013	Jan	44,844	157,229	883	4,205
2013	Feb	46,351	144,066	893	3,862
2013	Mar	48,937	162,958	853	3,740
2013	Annual	46,711	154,751	876	3,936

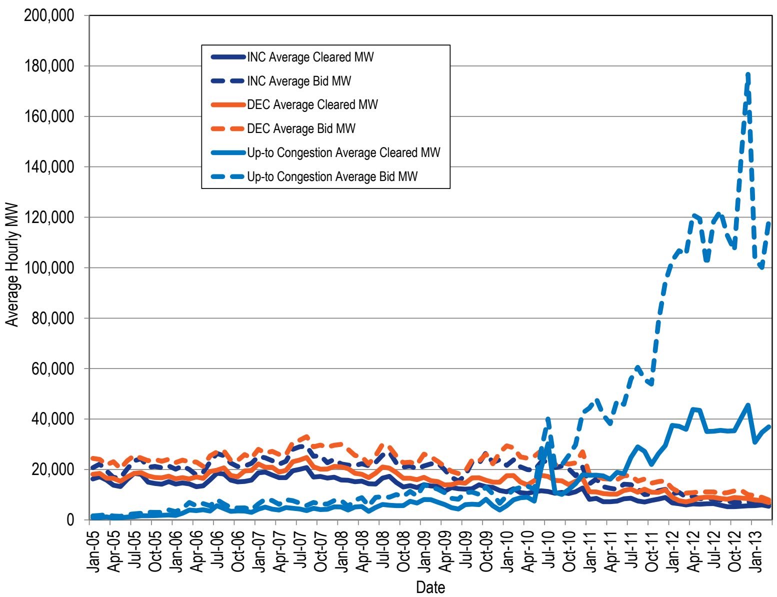
Table 2-47 shows the frequency with which generation offers, import or export transactions, up-to congestion transactions, decrement bids, increment offers and price-sensitive demand are marginal for each month.[54]

Table 2-47 Type of day-ahead marginal units: January through March 2013

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	3.0%	0.1%	93.5%	2.0%	1.4%	0.0%
Feb	2.6%	0.1%	94.6%	1.3%	1.4%	0.0%
Mar	1.6%	0.1%	97.3%	0.5%	0.5%	0.0%
Annual	2.3%	0.1%	95.4%	1.2%	1.0%	0.0%

Figure 2-24 shows the hourly volume of bid and cleared INC, DEC and up-to congestion bids by month.

Figure 2-24 Hourly volume of bid and cleared INC, DEC and Up-to Congestion bids (MW) by month: January, 2005 through March, 2013



54 These percentages compare the number of times that bids and offers of the specified type were marginal to the total number of marginal bids and offers. There is no weighting by time or by load.

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 2-48 shows, for the first three months of 2012 and 2013, the total increment offers and decrement bids by the type of parent organization: financial or physical. Table 2-49 shows for the first three months of 2012 and 2013, the total up-to congestion transactions by the type of parent organization.

The top five companies with cleared up-to congestion bids are financial and account for 63.6 percent of all the cleared up-to congestion MW in PJM in the first three months of 2013.

Table 2-48 PJM INC and DEC bids by type of parent organization (MW): January through March of 2012 and 2013

	2012 (Jan - Mar)		2013 (Jan - Mar)	
Category	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	17,440,367	37.1%	7,803,420	23.0%
Physical	29,532,769	62.9%	26,141,745	77.0%
Total	46,973,136	100.0%	33,945,165	100.0%

Table 2-49 PJM up-to congestion transactions by type of parent organization (MW): January through March of 2012 and 2013

	2012 (Jan - Mar)		2013 (Jan - Mar)	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	76,514,461	95.1%	94,709,907	93.8%
Physical	3,931,378	4.9%	6,211,701	6.2%
Total	80,445,839	100.0%	100,921,609	100.0%

Table 2-50 shows increment offers and decrement bids bid by top ten locations for the first three months of 2012 and 2013.

Table 2-50 PJM virtual offers and bids by top ten locations (MW): January through March of 2012 and 2013

2012 (Jan - Mar)					2013 (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	7,688,302	8,954,480	16,642,782	WESTERN HUB	HUB	6,709,062	7,469,243	14,178,305
AEP-DAYTON HUB	HUB	1,311,830	1,322,353	2,634,183	SOUTHIMP	INTERFACE	2,451,598	0	2,451,598
SOUTHIMP	INTERFACE	2,362,472	0	2,362,472	N ILLINOIS HUB	HUB	601,071	1,406,425	2,007,496
N ILLINOIS HUB	HUB	797,387	1,217,638	2,015,025	AEP-DAYTON HUB	HUB	855,706	915,790	1,771,496
PECO	ZONE	569,142	1,413,636	1,982,778	IMO	INTERFACE	1,415,648	26,744	1,442,392
PPL	ZONE	109,230	1,461,786	1,571,016	PPL	ZONE	21,829	1,416,128	1,437,957
MISO	INTERFACE	68,763	1,325,083	1,393,845	PECO	ZONE	37,216	850,576	887,793
IMO	INTERFACE	1,095,465	7,054	1,102,519	NYIS	INTERFACE	74,855	589,255	664,110
PSEG	ZONE	211,672	342,435	554,107	MISO	INTERFACE	53,127	535,276	588,403
BGE	ZONE	53,894	446,806	500,700	DOMINION HUB	HUB	99,832	370,797	470,629
Top ten total		14,268,157	16,491,270	30,759,427			12,319,944	13,580,235	25,900,179
PJM total		22,025,564	24,947,572	46,973,136			14,879,528	19,065,637	33,945,165
Top ten total as percent of PJM total		64.8%	66.1%	65.5%			82.8%	71.2%	76.3%

Table 2-51 shows up-to congestion transactions by import bids for the top ten locations for the first three months of 2012 and 2013.[55]

Table 2-51 PJM cleared up-to congestion import bids by top ten source and sink pairs (MW): January through March of 2012 and 2013

2012 (Jan - Mar)				
Imports				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	112 WILTON	EHVAGG	3,950,243
OVEC	INTERFACE	CONESVILLE 4	AGGREGATE	1,372,477
OVEC	INTERFACE	DEOK	ZONE	1,064,356
OVEC	INTERFACE	CONESVILLE 5	AGGREGATE	752,791
MISO	INTERFACE	N ILLINOIS HUB	HUB	724,225
OVEC	INTERFACE	CONESVILLE 6	AGGREGATE	701,270
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	616,066
MISO	INTERFACE	POWERTON 5	AGGREGATE	615,189
NYIS	INTERFACE	HUDSON BC	AGGREGATE	523,487
MISO	INTERFACE	COOK	EHVAGG	418,931
Top ten total				10,739,036
PJM total				39,854,575
Top ten total as percent of PJM total				26.9%
2013 (Jan - Mar)				
Imports				
Source	Source Type	Sink	Sink Type	MW
NYIS	INTERFACE	HUDSON BC	AGGREGATE	403,639
OVEC	INTERFACE	DEOK	ZONE	381,127
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	311,221
OVEC	INTERFACE	STUART 1	AGGREGATE	243,555
MISO	INTERFACE	112 WILTON	EHVAGG	236,497
OVEC	INTERFACE	ZIMMER	AGGREGATE	219,178
OVEC	INTERFACE	CONESVILLE 5	AGGREGATE	191,405
OVEC	INTERFACE	BECKJORD 6	AGGREGATE	173,209
OVEC	INTERFACE	OHIO HUB	HUB	172,597
OVEC	INTERFACE	STUART 4	AGGREGATE	170,534
Top ten total				2,502,961
PJM total				11,003,102
Top ten total as percent of PJM total				22.7%

Table 2-52 shows up-to congestion transactions by export bids for the top ten locations for the first three months of 2012 and 2013.

Table 2-52 PJM cleared up-to congestion export bids by top ten source and sink pairs (MW): January through March of 2012 and 2013

2012 (Jan - Mar)				
Exports				
Source	Source Type	Sink	Sink Type	MW
ROCKPORT	EHVAGG	OVEC	INTERFACE	1,653,313
ROCKPORT	EHVAGG	SOUTHWEST	AGGREGATE	1,079,308
23 COLLINS	EHVAGG	MISO	INTERFACE	931,276
167 PLANO	EHVAGG	MISO	INTERFACE	757,345
SPORN 3	AGGREGATE	OVEC	INTERFACE	646,956
WESTERN HUB	HUB	MISO	INTERFACE	633,292
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	570,882
ROCKPORT	EHVAGG	MISO	INTERFACE	544,717
QUAD CITIES 1	AGGREGATE	NORTHWEST	INTERFACE	536,568
SPORN 5	AGGREGATE	OVEC	INTERFACE	530,900
Top ten total				7,884,555
PJM total				40,363,681
Top ten total as percent of PJM total				19.5%
2013 (Jan - Mar)				
Exports				
Source	Source Type	Sink	Sink Type	MW
GAVIN	EHVAGG	OVEC	INTERFACE	440,608
F387 CHICAGOH	AGGREGATE	NIPSCO	INTERFACE	368,347
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	350,741
SPORN 3	AGGREGATE	OVEC	INTERFACE	293,548
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	253,264
JEFFERSON	EHVAGG	OVEC	INTERFACE	249,922
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	194,734
CULLODEN	EHVAGG	OVEC	INTERFACE	188,867
21 KINCA ATR24304	AGGREGATE	OVEC	INTERFACE	182,977
BIG SANDY CT4	AGGREGATE	SOUTHWEST	INTERFACE	166,899
Top ten total				2,689,906
PJM total				14,919,573
Top ten total as percent of PJM total				18.0%

55 The source and sink aggregates in these tables refer to the name and location of a bus and do not include information about the behavior of any individual market participant.

Table 2-53 shows up-to congestion transactions by wheel bids for the top ten locations for the first three months of 2012 and 2013.

Table 2-53 PJM cleared up-to congestion wheel bids by top ten source and sink pairs (MW): January through March of 2012 and 2013

2012 (Jan - Mar)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	50,943
NIPSCO	INTERFACE	NORTHWEST	INTERFACE	18,738
SOUTHWEST	AGGREGATE	OVEC	INTERFACE	13,961
NORTHWEST	INTERFACE	MISO	INTERFACE	13,833
SOUTHEAST	AGGREGATE	SOUTHWEST	AGGREGATE	11,601
SOUTHWEST	AGGREGATE	SOUTHEXP	INTERFACE	10,572
OVEC	INTERFACE	SOUTHEXP	INTERFACE	9,346
NYIS	INTERFACE	NEPTUNE	INTERFACE	8,786
NORTHWEST	INTERFACE	SOUTHEXP	INTERFACE	8,593
NIPSCO	INTERFACE	IMO	INTERFACE	7,855
Top ten total				154,227
PJM total				227,583
Top ten total as percent of PJM total				67.8%
2013 (Jan - Mar)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	438,456
IMO	INTERFACE	NYIS	INTERFACE	198,859
MISO	INTERFACE	NIPSCO	INTERFACE	133,002
LINDENVFT	INTERFACE	NYIS	INTERFACE	76,636
MISO	INTERFACE	SOUTHEXP	INTERFACE	53,205
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	51,723
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	41,180
NORTHWEST	INTERFACE	MISO	INTERFACE	40,196
MISO	INTERFACE	OVEC	INTERFACE	33,088
NYIS	INTERFACE	LINDENVFT	INTERFACE	27,935
Top ten total				1,094,280
PJM total				1,342,254
Top ten total as percent of PJM total				81.5%

On November 1, 2012, PJM eliminated the requirement for market participants to specify an interface pricing point as either the source or sink of an up-to congestion transaction.[56] Up-to congestion transactions can now be made at internal buses. The top ten internal up-to congestion transaction locations were 8.0 percent of the PJM total internal up-to congestion transactions in the first three months of 2013.

Table 2-54 shows up-to congestion transactions by internal bids for the top ten locations for the first three months of 2013.

Table 2-54 PJM cleared up-to congestion internal bids by top ten source and sink pairs (MW): January through March of 2013

2013 (Jan - Mar)				
Internal				
Source	Source Type	Sink	Sink Type	MW
SUNBURY 1-3	AGGREGATE	CITIZENS	AGGREGATE	1,298,253
YADKIN	EHVAGG	FENTRESS	EHVAGG	763,731
NAPERVILLE	AGGREGATE	WINNETKA	AGGREGATE	600,547
CORDOVA	AGGREGATE	QUAD CITIES 2	AGGREGATE	563,064
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	501,756
BROADFORD	EHVAGG	CLINCH RIVER 1	AGGREGATE	487,787
NAPERVILLE	AGGREGATE	ZION 1	AGGREGATE	487,593
DELI	AGGREGATE	BYRON 1	AGGREGATE	461,131
GENEVA	AGGREGATE	WINNETKA	AGGREGATE	377,375
NAPERVILLE	AGGREGATE	CHICAGO HUB	HUB	358,100
Top ten total				5,899,339
PJM total				73,656,680
Top ten total as percent of PJM total				8.0%

Table 2-55 shows the number of source-sink pairs that were offered and cleared monthly in 2012 and the first three months of 2013. The increase in average offered and cleared source-sink pairs in November and December of 2012 and the first three months of 2013 illustrates that PJM's modification of the rules governing the location of up-to congestion transactions bids resulted in a significant increase in the number of offered and cleared up-to congestion transactions. The increase in source-sink pairs available for up-to congestion transactions has also led to more dispersion in the number of cleared up-to congestion transaction internal bids by location.

56 For more information, see the *2012 State of the Market Report for PJM* Section 8, "Interchange Transactions," Up-to Congestion.

Table 2-55 Number of PJM offered and cleared source and sink pairs: January 2012 through March of 2013

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2012	Jan	1,771	2,182	1,126	1,568
2012	Feb	1,816	2,198	1,156	1,414
2012	Mar	1,746	2,004	1,128	1,353
2012	Apr	1,753	2,274	1,117	1,507
2012	May	1,866	2,257	1,257	1,491
2012	Jun	2,145	2,581	1,425	1,897
2012	Jul	2,168	2,800	1,578	2,078
2012	Aug	2,541	3,043	1,824	2,280
2012	Sep	2,140	3,032	1,518	2,411
2012	Oct	2,344	3,888	1,569	2,625
2012	Nov	4,102	8,142	2,829	5,811
2012	Dec	9,424	13,009	5,025	8,071
2012	Jan-Oct	2,031	3,888	1,371	2,625
2012	Nov-Dec	6,806	13,009	3,945	8,071
2012	Annual	2,818	3,951	1,796	2,709
2013	Jan	6,580	10,548	3,291	5,060
2013	Feb	4,891	7,415	2,755	3,907
2013	Mar	4,858	7,446	2,868	4,262
2013	Annual	5,443	8,470	2,972	4,410

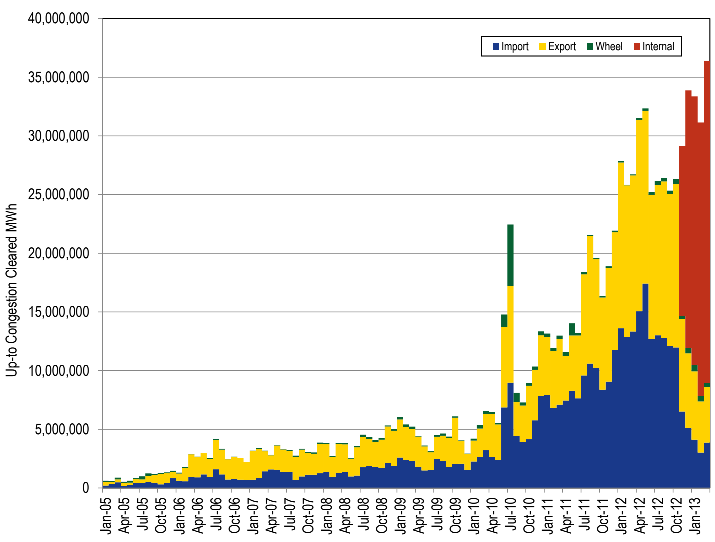
Table 2-56 PJM cleared up-to congestion transactions by type (MW): January through March of 2012 and 2013

	2012 (Jan - Mar)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	10,739,036	7,884,555	154,227	NA	12,986,604
PJM total (MW)	39,854,575	40,363,681	227,583	NA	80,445,839
Top ten total as percent of PJM total	26.9%	19.5%	67.8%	NA	16.1%
PJM total as percent of all up-to congestion transactions	49.5%	50.2%	0.3%	NA	100.0%
	2013 (Jan - Mar)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	2,502,961	2,689,906	1,094,280	5,899,339	6,042,928
PJM total (MW)	11,003,102	14,919,573	1,342,254	73,656,680	100,921,609
Top ten total as percent of PJM total	22.7%	18.0%	81.5%	8.0%	6.0%
PJM total as percent of all up-to congestion transactions	10.9%	14.8%	1.3%	73.0%	100.0%

Table 2-56 and Figure 2-25 show total cleared up-to congestion transactions by type for the first three months of 2012 and 2013. Internal up-to congestion transactions in the first three months of 2013 were 73.0 percent of all up-to congestion transactions for the first three months of 2013.

Figure 2-25 shows the spike in internal up-to congestion transactions in November and December of 2012 and the first three months of 2013, following the November 1, 2012, rule change permitting such transactions.

Figure 2-25 PJM cleared up-to congestion transactions by type (MW): January 2005 through March of 2013



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. There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis (Figure 2-27).

Table 2-57 shows, day-ahead and real-time prices were relatively close, on average, in the first three months of 2012 and 2013.

Table 2-57 Day-ahead and real-time average LMP (Dollars per MWh): January through March of 2012 and 2013[57]

	2012 (Jan - Mar)				2013 (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	$30.82	$30.38	($0.43)	(1.4%)	$36.46	$36.33	($0.13)	(0.4%)
Median	$30.04	$28.82	($1.22)	(4.2%)	$34.45	$32.29	($2.16)	(6.7%)
Standard deviation	$6.63	$11.63	$5.00	43.0%	$9.78	$18.47	$8.69	47.0%
Peak average	$33.78	$33.75	($0.03)	(0.1%)	$40.55	$41.02	$0.47	1.1%
Peak median	$32.08	$30.65	($1.43)	(4.7%)	$37.86	$35.02	($2.84)	(8.1%)
Peak standard deviation	$6.30	$12.05	$5.75	47.7%	$10.81	$22.56	$11.75	52.1%
Off peak average	$28.19	$27.41	($0.79)	(2.9%)	$32.87	$32.22	($0.65)	(2.0%)
Off peak median	$27.75	$26.75	($1.00)	(3.7%)	$31.64	$29.82	($1.82)	(6.1%)
Off peak standard deviation	$5.76	$10.38	$4.62	44.5%	$7.05	$12.59	$5.54	44.0%

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

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 as well as conditions in real time that are difficult or impossible to predict.

Table 2-58 shows the difference between the Real-Time and the Day-Ahead Energy Market Prices for the first three months of the 13-year period 2001 to 2013.

Table 2-58 Day-ahead and real-time average LMP (Dollars per MWh): January through March of 2001 through 2013

(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%)
2013	$36.46	$36.33	($0.13)	(0.4%)

Table 2-59 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 three months of the years 2007 through 2013.

Table 2-59 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): January through March of 2007 through 2013

	2007		2008		2009		2010		2011		2012		2013	
LMP	Frequency	Cumulative Percent	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%	0	0.00%
($150) to ($100)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.05%	0	0.00%	0	0.00%
($100) to ($50)	14	0.65%	21	0.96%	1	0.05%	5	0.23%	17	0.83%	2	0.09%	0	0.00%
($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%	1,542	71.42%
$0 to $50	847	96.11%	740	94.82%	788	98.93%	547	98.24%	619	97.31%	601	99.36%	587	98.61%
$50 to $100	73	99.49%	97	99.27%	21	99.91%	33	99.77%	51	99.68%	12	99.91%	23	99.68%
$100 to $150	7	99.81%	14	99.91%	2	100.00%	1	99.81%	6	99.95%	2	100.00%	3	99.81%
$150 to $200	0	99.81%	1	99.95%	0	100.00%	4	100.00%	1	100.00%	0	100.00%	3	99.95%
$200 to $250	1	99.86%	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.95%
$250 to $300	1	99.91%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	100.00%
$300 to $350	2	100.00%	0	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%	0	100.00%
$400 to $450	0	100.00%	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%	0	100.00%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Figure 2-26 shows the hourly differences between day-ahead and real-time load-weighted hourly LMP in the first three months of 2013.

Figure 2-26 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: January through March of 2013

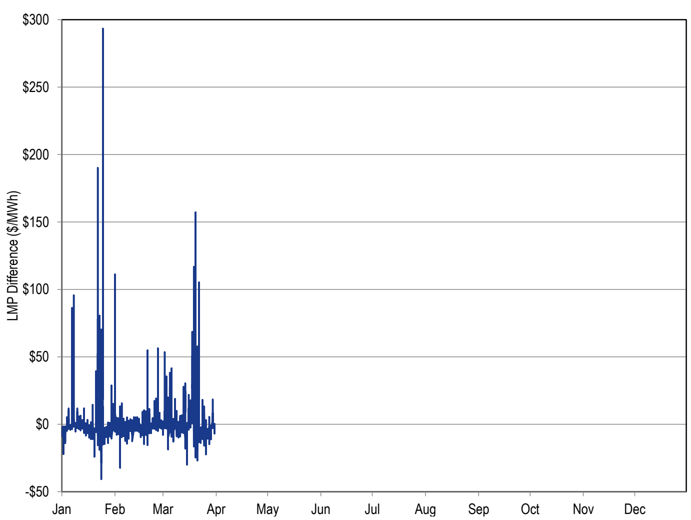


Figure 2-27 shows the monthly average differences between the day-ahead and real-time LMP in the first three months of 2013.

Figure 2-27 Monthly average of real-time minus day-ahead LMP: January through March of 2013

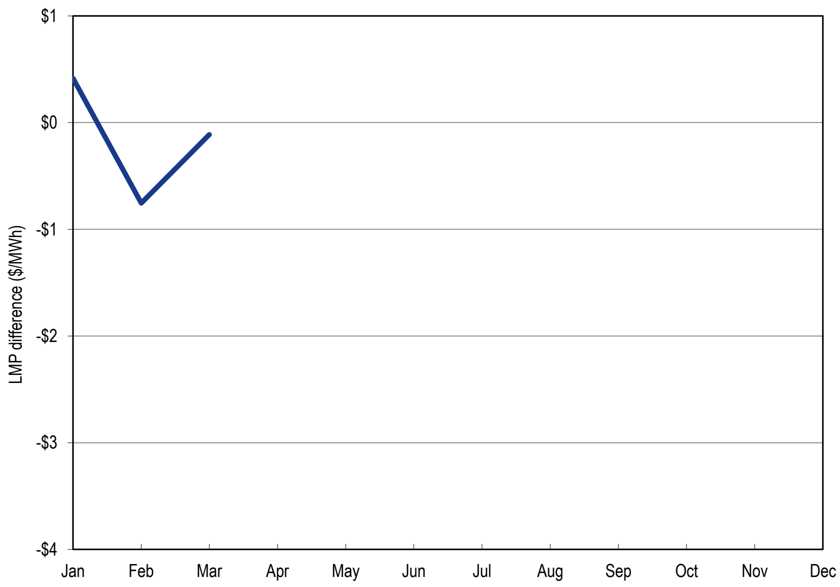
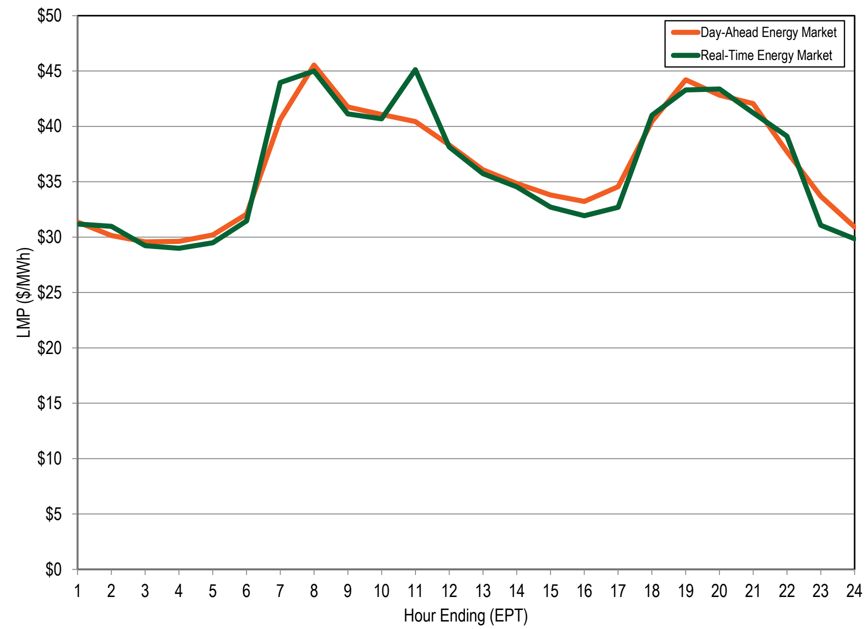


Figure 2-28 shows day-ahead and real-time LMP on an average hourly basis for the first three months of 2013.

Figure 2-28 PJM system hourly average LMP: January through March of 2013



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 2-60 shows the monthly average share of real-time load served by self-supply, bilateral contract and spot purchase in 2012 and 2013 based on parent company. For the first three months of 2013, 10.5 percent of real-time load was supplied by bilateral contracts, 22.8 percent by spot market purchase and 66.8 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased 1.4 percentage points, reliance on spot supply decreased by 0.4 percentage points and reliance on self-supply decreased by 1.0 percentage points.

Table 2-60 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2012 through 2013

	2012			2013			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	8.9%	22.0%	69.1%	10.4%	22.3%	67.3%	1.5%	0.2%	(1.8%)
Feb	8.8%	21.2%	70.0%	10.5%	22.0%	67.5%	1.7%	0.8%	(2.4%)
Mar	9.4%	23.6%	67.1%	10.4%	24.2%	65.4%	1.1%	0.6%	(1.6%)
Apr	9.4%	23.8%	66.8%						
May	8.6%	23.5%	67.9%						
Jun	8.7%	22.3%	69.0%						
Jul	8.0%	22.7%	69.3%						
Aug	8.5%	23.6%	67.9%						
Sep	9.1%	24.4%	66.5%						
Oct	9.6%	25.5%	64.9%						
Nov	9.9%	23.9%	66.3%						
Dec	10.2%	22.6%	67.3%						
Annual	9.0%	23.2%	67.8%	10.5%	22.8%	66.8%	1.4%	(0.4%)	(1.0%)

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 2-61 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 the first three months of 2013, 6.9 percent of day-ahead load was supplied by bilateral contracts, 22.6 percent by spot market purchases, and 70.5 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased by 0.2 percentage points, reliance on spot supply increased by 0.3 percentage points, and reliance on self-supply decreased by 0.5 percentage points.

Table 2-61 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: 2012 through 2013

	2012			2013			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	6.6%	21.4%	72.0%	6.8%	22.1%	71.1%	0.2%	0.7%	(0.9%)
Feb	6.7%	20.0%	73.3%	7.0%	22.1%	71.0%	0.3%	2.1%	(2.3%)
Mar	6.7%	22.8%	70.5%	7.0%	23.6%	69.4%	0.3%	0.8%	(1.1%)
Apr	6.7%	22.8%	70.6%						
May	6.6%	22.7%	70.7%						
Jun	7.7%	20.7%	71.6%						
Jul	5.9%	22.0%	72.0%						
Aug	6.4%	22.5%	71.0%						
Sep	6.5%	23.9%	69.6%						
Oct	6.6%	25.2%	68.2%						
Nov	6.9%	22.7%	70.5%						
Dec	7.0%	21.2%	71.8%						
Annual	6.7%	22.3%	71.0%	6.9%	22.6%	70.5%	0.2%	0.3%	(0.5%)