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 2013, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM Energy Market results were competitive in 2013.

Table 3-1 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 2013 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1167 with a minimum of 844 and a maximum of 1604 in 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. The expanding role of UTCs in the Day-Ahead Energy Market continues to cause concerns.

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,

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. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). 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 *2013 State of the Market Report for PJM*, Appendix A, "PJM Geography."

2 OATT Attachment M.

PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[3]

Overview

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. Average offered real-time generation increased by 2,546 MW, or 1.5 percent, from 173,414 MW in the summer of 2012 to 175,960 MW in the summer of 2013.[4] The increase in offered generation was in part the result of the integration of the East Kentucky Power Cooperative (EKPC) Transmission Zone in the second quarter of 2013. In 2013, 1,127 MW of new capacity were added to PJM. This new generation was more than offset by the deactivation of 18 units (2,863 MW) since January 1, 2013.

  PJM average real-time generation in 2013 increased by 1.2 percent from 2012, from 88,708 MW to 89,769 MW. The PJM average real-time generation in 2013 would have increased by 0.5 percent from 2012, from 88,708 MW to 89,126 MW, if the EKPC Transmission Zone had not been included.[5]

  PJM average day-ahead supply in 2013, including INCs and up-to congestion transactions, increased by 10.3 percent from 2012, from 134,479 MW to 148,323 MW. The PJM average day-ahead supply, including INCs and up-to congestion transactions, would have increased by 9.7 percent from 2012, from 134,479 MW to 147,541 MW, if the EKPC Transmission Zone had not been included. The day-ahead supply growth was 758.3 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.

- **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.

- **Generation Fuel Mix.** During 2013, coal units provided 44.3 percent, nuclear units 34.8 percent and gas units 16.3 percent of total generation. Compared to 2012, generation from coal units increased 6.2 percent, generation from nuclear units increased 1.4 percent, and generation from gas units decreased 12.2 percent. The change is primarily a result of increased natural gas prices in 2013, particularly in eastern zones, and lower or constant coal prices.

- **Marginal Resources.** In the PJM Real-Time Energy Market, for 2013, coal units were 57.7 percent and natural gas units were 32.4 percent of marginal resources. In 2012, coal units were 58.8 percent and natural gas units were 30.3 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market, for 2013, up-to congestion transactions were marginal for 96.4 percent of marginal resources, the INCs were marginal for 1.3 percent of marginal resources, the DECs were marginal for 1.1 percent of marginal resources, and generation resources were marginal in only 1.2 percent of marginal resources in 2013.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM system peak load for 2013 was 157,508 MW in the HE 1700 on July 18, 2013, which was 3,165 MW, or 2.1 percent, higher than the PJM peak load for 2012, which was 154,344 MW in the HE 1700 on July 17, 2012.[6]

  PJM average real-time load in 2013 increased by 1.5 percent from 2012, from 87,011 MW to 88,332 MW. The PJM average real-time load in 2013 would have increased by 0.6 percent from 2012, from 87,011 MW to 87,537 MW, if the EKPC Transmission Zone had not been included.

  PJM average day-ahead demand in 2013, including DECs and up-to congestion transactions, increased by 10.1 percent from 2012, from 131,612 MW to 144,858 MW. The PJM average day-ahead demand, including DECs and up-to congestion transactions, would have increased 9.4 percent from 2012, from 131,612 MW to 143,962 MW, if the EKPC

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

5 The EKPC Zone was integrated on June 1, 2013.

6 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2013 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).

Transmission Zone had not been included. The day-ahead demand growth was 573.3 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions.

- **Supply and Demand: 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 2013, 10.6 percent of real-time load was supplied by bilateral contracts, 25.0 percent by spot market purchases and 64.4 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased 1.6 percentage points, reliance on spot market purchases increased by 1.8 percentage points and reliance on self-supply decreased by 3.3 percentage points. For 2013, 8.0 percent of day-ahead load was supplied by bilateral contracts, 24.5 percent by spot market purchases, and 67.5 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased by 1.4 percentage points, reliance on spot market purchases increased by 2.2 percentage points, and reliance on self-supply decreased by 3.6 percentage points.

- **Supply and Demand: Scarcity.** PJM's market did not experience any reserve-based scarcity events in 2013. However, PJM declared a hot weather alert in all or parts of the PJM territory on seventeen days in 2013 compared to twenty eight days in 2012. PJM declared cold weather alerts on seven days in 2013 and did not declare any cold weather alerts in 2012. PJM issued a maximum emergency generation alert on four days in 2013 compared to one day in 2012. PJM declared emergency mandatory load management reductions (long lead time) on five days in 2013 and on two days in 2012. PJM declared emergency mandatory load management reductions (short lead time) on one day each in 2013 and 2012. PJM declared maximum emergency generation actions on five days in 2013 that resulted in PJM direction to load maximum emergency capacity, compared to two days in 2012. PJM declared a voltage reduction warning and reduction of non-critical plant load on one day each in 2013 and 2012.

  In the week beginning September 9, 2013, unusually high temperatures in the PJM territory combined with some generation and transmission outages resulted in PJM issuing load shed directives in specific locations.

Market Behavior

- **Offer Capping for Local Market Power.** 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 Day-Ahead Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours remained at 0.1 percent in 2012 and 2013. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 0.8 percent in 2012 to 0.4 percent in 2013.

  In 2013, 12 control zones experienced congestion resulting from one or more constraints binding for 100 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.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0.8 percent in 2012 to 3.1 percent in 2013. In the Real-Time Energy Market, for units committed to provide energy for reliability reasons, offer-capped unit hours increased from 0.9 percent in 2012 to 2.5 percent in 2013.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. The markup index for each marginal unit is calculated as (Price – Cost)/Price. The markup index is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost.

The average markup index of marginal units was calculated by offer price category.

In the PJM Real-Time Energy Market in 2013, 93.0 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.04. Nonetheless, some marginal units do have substantial markups.

In the PJM Day-Ahead Energy Market in 2013, 99.0 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.00. Nonetheless, some marginal units do have substantial markups.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 112 units eligible for FMU or AU status in at least one month during 2013, 22 units (19.6 percent) were FMUs or AUs for all of 2013, and 10 units (8.9 percent) qualified in only one month of 2013.
- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up-to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. In 2013, up-to congestion transactions continued to displace increment offers and decrement bids. The average hourly submitted and cleared increment offer MW decreased 23.4 and 14.5 percent, and the average hourly submitted and cleared decrement bid MW decreased 18.0 and 14.6 percent in 2013 compared to 2012. The average hourly up-to congestion transaction submitted and cleared MW increased 46.3 and 34.6 percent in 2013 compared to 2012. The top five companies with cleared up-to congestion transactions are financial and account for 57.4 percent of all the cleared up-to congestion MW in PJM in 2013.

Market Performance

- **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 2013 compared to 2012. The system average LMP was 10.4 percent higher in 2013 than in 2012, $36.55 per MWh versus $33.11 per MWh. The load-weighted average LMP was 9.7 percent higher in 2013 than in 2012, $38.66 per MWh versus $35.23 per MWh.

  PJM Day-Ahead Energy Market Prices increased in 2013 compared to 2012. The system average LMP was 13.3 percent higher in 2013 than in 2012, $37.15 per MWh versus $32.79 per MWh. The load-weighted average LMP was 12.7 percent higher in 2013 than in 2012, $38.93 per MWh versus $34.55 per MWh.[7]
- **Components of LMP.** LMPs result from the operation of a market based on security-constrained, economic (least-cost) dispatch in which marginal units determine system LMPs, based on their offers. 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.

  In the PJM Real-Time Energy Market, for 2013, 46.6 percent of the load-weighted LMP was the result of coal costs, 27.6 percent was the result of gas costs and 0.63 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market, for 2013, 71.9 percent of the load-weighted LMP was the result of up-to congestion transactions, 11.9 percent was the result of the cost of coal and 5.7 percent was the result of the cost of gas.
- **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.

  In the PJM Real-Time Energy Market in 2013, the adjusted markup was positive, $0.77 per MWh or 2.0 percent of the PJM real-time, load-weighted average LMP, primarily as a result of competitive

7 Tables reporting zonal and jurisdictional load and prices are in the *2013 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

behavior by coal units. In 2013, the real time load-weighted average LMP for the month of July had the highest markup component, $4.37 per MWh using adjusted cost offers. This corresponds to 8.6 percent of July's real time load-weighted average LMP. The July results demonstrate that markups can increase significantly during high demand periods.

In the PJM Day-Ahead Energy Market, marginal INC, DEC and transactions have zero markups. In 2013, the adjusted markup component of LMP resulting from generation resources was negative, -$0.53 per MWh.

The overall markup 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.

- **Price Convergence.** Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. The difference between annual average day-ahead and real-time prices was $0.32 per MWh in 2012 and -$0.60 per MWh in 2013. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Recommendations

- The MMU recommends the elimination of FMU and AU adders. Since the implementation of FMU adders, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007, and 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. This recommendation is currently being evaluated in the PJM stakeholder process.
- The PJM Tariff defines offer capped units as those units capped to maintain system reliability as a result of limits on transmission capability.[8] Offer capping for providing black start service does not meet this criterion. The MMU recommends that black start units not be given FMU status under the current rules.
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[9]
- The MMU recommends that PJM not use the ATSI Interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product.
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice.
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013.
- The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent.
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule physical power.
- There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[10] The MMU recommends that PJM include in the appropriate manual an explanation of the initial creation of

8 PJM OATT, 6.4 Offer Price Caps., (February 25, 2014), p. 1909.

9 PJM OATT, 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.

10 The general definition of a hub can be found in "Manual 35: Definitions and Acronyms," Revision 22 (February 28, 2013).

hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[11]

- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load weighted LMP.
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters.

Conclusion

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

Average real-time offered generation increased by 2,546 MW in the summer of 2013 compared to the summer of 2012, while peak load increased by 3,165 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. 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 2013 generally reflected supply-demand fundamentals.

The high load conditions in the summer of 2013 illustrated a number of issues that are addressed in the MMU recommendations.

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.[12] 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.

PJM also offer caps units that are committed for reliability reasons in addition to units committed to provide constraint relief. Specifically, units that are committed to provide reactive support and black start service are offer capped in the energy market. These units are committed manually in both the Day-Ahead and Real-Time Energy Markets. Before 2011, these units were generally economic in the energy market. Since 2011, the percentage of hours when these units were not economic in the Real-Time Energy Market has steadily

11 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.

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

increased. In the Day-Ahead Energy Market, PJM started to commit these units as offer capped in September 2012, as part of a broader effort to maintain consistency between Real-Time and Day-Ahead Energy Markets.

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

The overall energy market results support the conclusion that energy 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 2013.

Market Structure

Market Concentration

Analyses of supply curve segments of the PJM Energy Market for 2013 indicate moderate concentration in the base load segment, but high concentration in the intermediate and peaking segments.[13] 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 were generally effective in preventing the exercise of market power in these areas during 2013.

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 3-2).

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.[14]

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

14 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)

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during 2013 was moderately concentrated (Table 3-2).

Table 3-2 PJM hourly Energy Market HHI: 2012 and 2013[15]

	Hourly Market HHI (2012)	Hourly Market HHI (2013)
Average	1240	1167
Minimum	931	844
Maximum	1657	1604
Highest market share (One hour)	32%	31%
Average of the highest hourly market share	23%	22%
# Hours	8,784	8,760
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

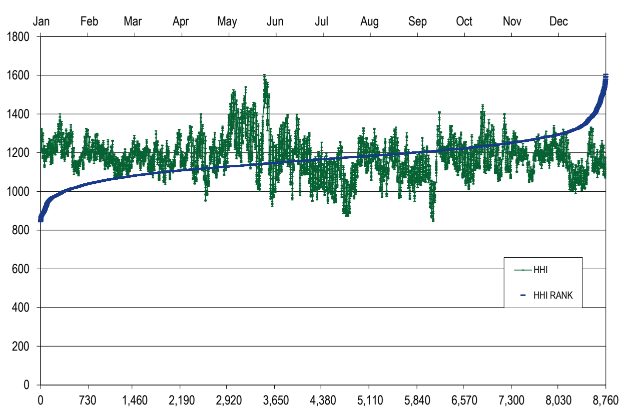
Table 3-3 includes 2013 HHI values by supply curve segment, including base, intermediate and peaking plants.

Table 3-3 PJM hourly Energy Market HHI (By supply segment): 2012 and 2013

	2012			2013		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	1025	1239	1624	878	1064	1464
Intermediate	787	1625	3974	946	2527	9194
Peak	679	5262	10000	580	6397	10000

Figure 3-1 presents the 2013 hourly HHI values in chronological order and an HHI duration curve.

Figure 3-1 PJM hourly Energy Market HHI: 2013



Ownership of Marginal Resources

Table 3-4 shows the contribution to PJM real-time, load-weighted LMP by individual marginal resource owner.[16] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of 2013, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. The results show that in 2013, the offers of one company contributed 21.7 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 56.2 percent of the real-time, load-weighted, average PJM system LMP. In comparison, during 2012, the offers of one company contributed 22.0 percent of the real time, load-weighted PJM system LMP and offers of the top four companies contributed 54.3 percent of the real-time, load-weighted, average PJM system LMP.

Table 3-4 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): 2012 and 2013

2012		2013	
Company	Percent of Price	Company	Percent of Price
1	22.0%	1	21.7%
2	12.8%	2	13.1%
3	11.6%	3	11.1%
4	7.9%	4	10.2%
5	7.8%	5	6.7%
6	6.2%	6	4.3%
7	5.7%	7	4.0%
8	5.2%	8	3.6%
9	3.7%	9	3.3%
Other (55 companies)	17.2%	Other (59 companies)	22.0%

Table 3-5 shows the contribution to PJM day-ahead, load-weighted LMP by individual marginal resource owner.[17] The contribution of each marginal resource to price at each load bus is calculated hourly for 2012 and 2013 period and summed by the company that offers the marginal resource into the Day-Ahead Energy Market.

15 This analysis includes all hours in 2013, regardless of congestion.

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

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

Table 3-5 Marginal resource contribution to PJM day-ahead, load-weighted LMP (By parent company): 2012 and 2013

2012		2013	
Company	Percent of Price	Company	Percent of Price
1	15.9%	1	23.1%
2	6.8%	2	9.1%
3	6.2%	3	8.7%
4	6.1%	4	8.1%
5	5.6%	5	5.3%
6	4.6%	6	3.2%
7	4.1%	7	3.1%
8	4.0%	8	2.7%
9	3.5%	9	2.5%
Other (145 companies)	43.2%	Other (147 companies)	34.2%

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 Energy Market. INC offers, DEC bids and up-to congestion transactions are dispatchable injections and withdrawals in the Day-Ahead Energy Market that can set price via their offers and bids.

Table 3-6 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 2013, coal units were 57.75 percent and natural gas units were 32.39 percent of marginal resources. In 2012, coal units were 58.84 percent and natural gas units were 30.35 percent of the total marginal resources.[18]

The results reflect the dynamics of an LMP market. When there is a single constraint, there are two marginal units. For example, a significant west to east constraint could be binding with a gas unit marginal in the east and a coal unit marginal in the west. As a result, although the dispatch of natural gas units has increased and gas units set price for more hours as marginal resources in the Real-Time Energy Market, this does not necessarily reduce the proportion of hours in which coal units are marginal. In 2013, coal and gas were both marginal in 24.7 percent of the five-minute intervals, natural gas units were marginal with no marginal coal units in 21.4 percent of the intervals and coal units were marginal with no marginal natural gas units in 53.4 percent of the intervals.

In 2013, 46.3 percent of the wind marginal units had negative offer prices, 52.2 percent had zero offer prices and 1.5 percent had positive offer prices.

Table 3-6 Type of fuel used (By real-time marginal units): 2012 and 2013

Fuel Type	2012	2013
Coal	58.84%	57.75%
Gas	30.35%	32.39%
Oil	6.00%	4.79%
Wind	4.19%	4.76%
Other	0.47%	0.20%
Municipal Waste	0.13%	0.07%
Demand Response	0.00%	0.02%
Uranium	0.02%	0.02%

Table 3-7 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In 2013, up-to congestion transactions were 96.4 percent of the total marginal resources. In comparison, up-to congestion transactions were 88.4 percent of the total marginal resources in 2012.[19]

Table 3-7 Day-ahead marginal resources by type/fuel: 2012 and 2013

Type/Fuel	2012	2013
Up-to Congestion Transaction	88.4%	96.4%
DEC	4.3%	1.3%
INC	3.8%	1.1%
Coal	2.3%	0.8%
Gas	1.0%	0.4%
Dispatchable Transaction	0.1%	0.0%
Price Sensitive Demand	0.0%	0.0%
Wind	0.0%	0.0%
Oil	0.0%	0.0%
Diesel	0.0%	0.0%
Municipal Waste	0.0%	0.0%
Total	100.0%	100.0%

Supply

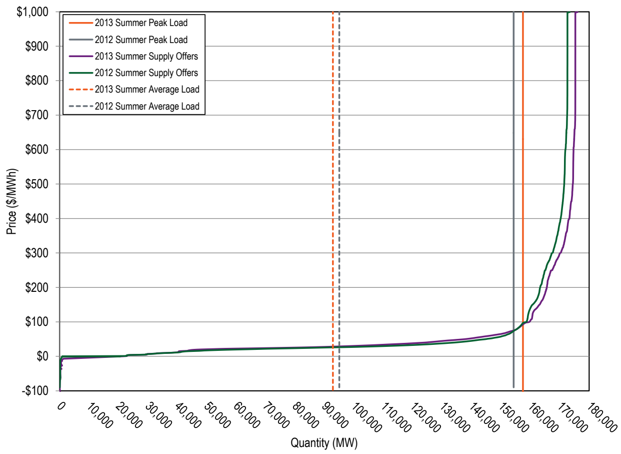
Supply includes physical generation and imports and virtual transactions.

Figure 3-2 shows the average PJM aggregate real-time generation supply curves, peak load and average load for the summers of 2012 and 2013.

18 The percentages of marginal fuel reported in the *2011 State of the Market Report for PJM*, were based on both locational pricing algorithm (LPA) and dispatch (SCED) marginal resources. Starting with the *2012 State of the Market Report for PJM*, marginal fuel percentages are based only on SCED. See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

19 PJM acknowledged an error in identifying marginal up-to congestion transactions following April 2013 changes to the day-ahead solution software. The software incorrectly increased the volume of marginal up-to congestion transactions. The fix to the problem is expected to be in place in 2014.

Figure 3-2 Average PJM aggregate real-time generation supply curves: Summer of 2012 and 2013



Energy Production by Fuel Source

Compared to 2012, generation from coal units increased 6.2 percent and generation from natural gas units decreased 12.5 percent (Table 3-8).[20] This represents a reversal of the recent trend of decreasing coal-fired output and increasing gas-fired output.

Table 3-8 PJM generation (By fuel source (GWh)): 2012 and 2013[21]

	2012		2013		Change in
	GWh	Percent	GWh	Percent	Output
Coal	332,762.0	42.1%	353,463.5	44.3%	6.2%
Standard Coal	323,043.5	40.9%	343,957.5	43.2%	6.3%
Waste Coal	9,718.5	1.2%	9,506.1	1.2%	(0.1%)
Nuclear	273,372.2	34.6%	277,277.8	34.8%	1.4%
Gas	148,230.4	18.8%	130,102.3	16.3%	(12.2%)
Natural Gas	146,007.5	18.5%	127,726.8	16.0%	(12.5%)
Landfill Gas	2,222.3	0.3%	2,321.0	0.3%	4.4%
Biomass Gas	0.5	0.0%	54.5	0.0%	10,323.4%
Hydroelectric	12,649.7	1.6%	14,085.0	1.8%	11.3%
Pumped Storage	6,521.9	0.8%	6,690.4	0.8%	2.6%
Run of River	6,127.8	0.8%	7,394.5	0.9%	20.7%
Wind	12,633.6	1.6%	14,826.9	1.9%	17.4%
Waste	5,177.6	0.7%	5,040.1	0.6%	(2.7%)
Solid Waste	4,200.3	0.5%	4,185.0	0.5%	(0.4%)
Miscellaneous	977.3	0.1%	855.1	0.1%	(12.5%)
Oil	5,030.9	0.6%	1,948.3	0.2%	(61.3%)
Heavy Oil	4,796.9	0.6%	1,730.7	0.2%	(63.9%)
Light Oil	218.9	0.0%	187.2	0.0%	(14.5%)
Diesel	9.9	0.0%	14.6	0.0%	47.5%
Kerosene	5.1	0.0%	15.7	0.0%	204.6%
Jet Oil	0.0	0.0%	0.1	0.0%	219.4%
Solar	233.5	0.0%	355.0	0.0%	52.0%
Battery	0.3	0.0%	0.7	0.0%	122.3%
Total	790,090.3	100.0%	797,099.6	100.0%	0.9%

20 Generation data are the sum of MWh for each fuel by source at every generation bus in PJM with positive output and reflect gross generation without offset for station use of any kind.

21 All generation is total gross generation output and does not net out the MWh withdrawn at a generation bus to provide auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps.

Table 3-9 Monthly PJM generation (By fuel source (GWh)): 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Coal	31,689.2	28,886.8	29,680.4	24,637.5	25,824.6	30,722.3	34,879.0	31,619.9	29,172.7	26,597.2	27,073.3	32,680.8	353,463.5
Standard Coal	30,814.3	28,102.4	28,670.2	24,060.8	24,962.6	29,884.0	33,916.0	30,862.6	28,562.7	25,984.7	26,427.7	31,709.5	343,957.5
Waste Coal	874.9	784.4	1,010.2	576.7	862.0	838.3	962.9	757.4	610.0	612.5	645.6	971.2	9,506.1
Nuclear	25,610.7	22,563.1	23,854.9	19,614.0	21,106.9	23,109.3	24,458.0	24,985.8	21,951.7	21,878.1	22,597.7	25,547.6	277,277.8
Gas	10,261.4	10,319.8	10,055.6	9,276.0	10,240.2	10,594.4	14,788.8	13,356.2	10,372.6	10,226.0	10,371.0	10,240.4	130,102.3
Natural Gas	10,072.4	10,143.6	9,859.7	9,096.1	10,047.2	10,404.5	14,593.7	13,158.1	10,174.8	10,009.5	10,156.1	10,011.1	127,726.8
Landfill Gas	189.0	176.2	195.9	179.9	193.0	189.8	195.1	198.1	196.2	203.1	197.6	207.2	2,321.0
Biomass Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7	13.4	17.3	22.1	54.5
Hydroelectric	1,234.0	1,127.0	1,215.8	1,273.0	1,250.7	1,401.7	1,609.2	1,167.5	865.7	855.1	853.1	1,232.1	14,085.0
Pumped Storage	488.1	440.0	486.4	481.9	562.9	730.2	848.5	710.2	528.9	491.3	433.4	488.6	6,690.4
Run of River	745.8	687.0	729.4	791.0	687.9	671.5	760.8	457.3	336.8	363.8	419.7	743.5	7,394.5
Wind	1,784.4	1,397.5	1,606.2	1,639.6	1,271.3	862.5	588.2	510.4	719.2	1,070.8	1,833.1	1,543.7	14,826.9
Waste	414.4	385.2	391.5	358.2	421.3	428.7	447.1	465.4	407.4	434.9	425.2	460.9	5,040.1
Solid Waste	324.8	301.5	325.2	323.9	349.9	368.6	385.3	382.3	350.4	356.5	348.3	368.2	4,185.0
Miscellaneous	89.6	83.7	66.2	34.3	71.4	60.2	61.8	83.0	57.0	78.4	76.8	92.7	855.1
Oil	62.5	23.8	50.3	79.1	220.3	190.7	629.8	154.8	209.2	116.0	17.0	194.8	1,948.3
Heavy Oil	55.8	21.9	27.9	66.8	206.1	179.4	575.0	139.9	167.6	101.1	7.5	181.8	1,730.7
Light Oil	4.2	1.5	17.7	11.7	13.2	10.7	43.6	13.0	36.7	14.9	7.8	12.1	187.2
Diesel	0.6	0.1	0.0	0.5	1.1	0.4	8.2	0.2	3.0	0.1	0.4	0.0	14.6
Kerosene	1.9	0.3	4.7	0.1	0.0	0.2	3.0	1.7	1.8	0.0	1.2	0.9	15.7
Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1
Solar	15.6	17.6	26.7	38.1	39.6	38.4	37.9	35.6	39.0	28.9	23.4	14.2	355.0
Battery	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.7
Total	71,072.0	64,720.7	66,881.4	56,915.4	60,374.9	67,348.2	77,438.0	72,295.8	63,737.6	61,207.1	63,193.7	71,914.6	797,099.6

Net Generation and Load

PJM sums all negative (injections) and positive (withdrawals) load at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) generation at each generation bus when calculating net generation. Netting withdrawals and injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

The zonal load-weighted LMP is calculated by weighting the zone's load bus LMPs by the zone's load bus accounting load. The definition of injections and withdrawals of energy as generation or load affects PJM's calculation of zonal load-weighted LMP.

The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP.

Real-Time Supply

Average offered real-time generation increased by 2,546 MW, or 1.5 percent, from 173,414 MW in the summer of 2012 to 175,960 MW in summer of 2013.[22] The increase in offered supply was in part the result of the integration of the East Kentucky Power Cooperative (EKPC) Transmission Zone in the second quarter of 2013. In 2013, 1,127 MW of new capacity were added to PJM. This new generation was more than offset by the deactivation of 18 units (2,863 MW) since January 1, 2013.

PJM average real-time generation in 2013 increased by 1.2 percent from 2012, from 88,708 MW to 89,769 MW. PJM average real-time generation in 2013 would have increased by 0.5 percent from 2012, from 88,708 MW

22 Calculated values shown in Section 3, "Energy Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

to 89,126 MW, if the EKPC Transmission Zone had not been included in the comparison.[23,24]

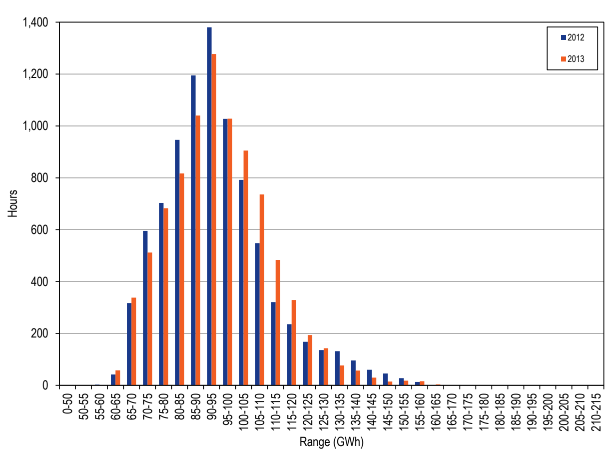
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **Self-Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a specific unit.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. A real-time import must have a valid OASIS reservation when offered, must have available ramp room to support the import, must be accompanied by a NERC e-Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Supply Duration

Figure 3-3 shows the hourly distribution of PJM real-time generation plus imports for 2012 and 2013.

Figure 3-3 Distribution of PJM real-time generation plus imports: 2012 and 2013[25]



23 The EKPC Transmission Zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013.

24 Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

25 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Real-Time, Average Supply

Table 3-10 presents summary real-time supply statistics for each year for the 14-year period from 2000 through 2013.[26]

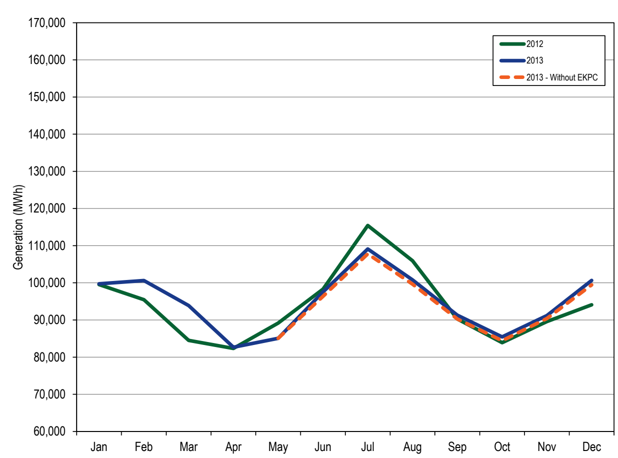
Table 3-10 PJM real-time average hourly generation and real-time average hourly generation plus average hourly imports: 2000 through 2013

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
Year	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2000	30,301	4,980	33,256	5,456	NA	NA	NA	NA
2001	29,553	4,937	32,552	5,285	(2.5%)	(0.9%)	(2.1%)	(3.1%)
2002	34,928	7,535	38,535	7,751	18.2%	52.6%	18.4%	46.7%
2003	36,628	6,165	40,205	6,162	4.9%	(18.2%)	4.3%	(20.5%)
2004	51,068	13,790	55,781	14,652	39.4%	123.7%	38.7%	137.8%
2005	81,127	15,452	86,353	15,981	58.9%	12.0%	54.8%	9.1%
2006	82,780	13,709	86,978	14,402	2.0%	(11.3%)	0.7%	(9.9%)
2007	85,860	14,018	90,351	14,763	3.7%	2.3%	3.9%	2.5%
2008	83,476	13,787	88,899	14,256	(2.8%)	(1.7%)	(1.6%)	(3.4%)
2009	78,026	13,647	83,058	14,140	(6.5%)	(1.0%)	(6.6%)	(0.8%)
2010	82,585	15,556	87,386	16,227	5.8%	14.0%	5.2%	14.8%
2011	85,775	15,932	90,511	16,759	3.9%	2.4%	3.6%	3.3%
2012	88,708	15,701	94,083	16,505	3.4%	(1.4%)	3.9%	(1.5%)
2013	89,769	15,012	94,833	15,878	1.2%	(4.4%)	0.8%	(3.8%)

PJM Real-Time, Monthly Average Generation

Figure 3-4 compares the real-time, monthly average hourly generation in 2013 with those in 2012.

Figure 3-4 PJM real-time average monthly hourly generation: January 2012 through December 2013



26 The import data in this table is not available before June 1, 2000. The data that includes imports in 2000 is calculated from the last six months of that year.

Day-Ahead Supply

PJM average day-ahead supply in 2013, including INCs and up-to congestion transactions, increased by 10.3 percent from 2012, from 134,479 MW to 148,323 MW. The PJM average day-ahead supply in 2013, including INCs and up-to congestion transactions, would have increased by 9.7 percent from 2012, from 134,479 MW to 147,541 MW, if the EKPC Transmission Zone had not been included in the comparison.

The day-ahead supply growth was 758.3 percent higher in 2013 than the real-time generation growth in 2012 because of the continued growth of up-to congestion transactions. If 2013 up-to congestion transactions had been held to 2012 levels, the day-ahead supply, including INCs and up-to congestion transactions, would have increased 0.4 percent instead of 10.3 percent and day-ahead supply growth would have been 63.3 percent lower than the real-time generation growth.

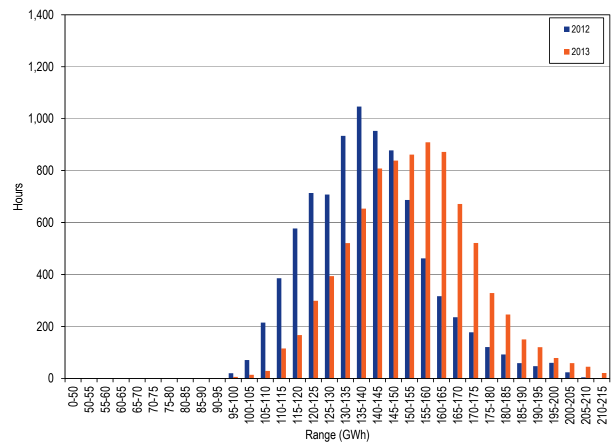
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **Self-Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a unit.
- **Increment Offer (INC).** Financial offer to supply MWh and corresponding offer prices. INCs can be submitted by any market participant.
- **Up-to Congestion Transaction.** 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. An up-to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. An import must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An import energy transaction that clears the Day-Ahead Energy Market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an import energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the real-time energy market scheduling process.

PJM Day-Ahead Supply Duration

Figure 3-5 shows the hourly distribution of PJM day-ahead supply, including increment offers, up-to congestion transactions, and imports for 2012 and 2013.

Figure 3-5 Distribution of PJM day-ahead supply plus imports: 2012 and 2013[27]



27 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Day-Ahead, Average Supply

Table 3-11 presents summary day-ahead supply statistics for each year of the 14-year period from 2000 through 2013.[28]

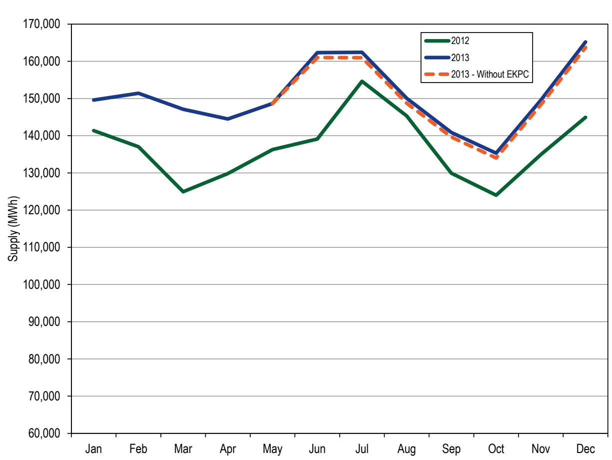
Table 3-11 PJM day-ahead average hourly supply and day-ahead average hourly supply plus average hourly imports: 2000 through 2013

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
Year	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2000	27,135	4,858	27,589	4,895	NA	NA	NA	NA
2001	26,762	4,595	27,497	4,664	(1.4%)	(5.4%)	(0.3%)	(4.7%)
2002	31,434	10,007	31,982	10,015	17.5%	117.8%	16.3%	114.7%
2003	40,642	8,292	41,183	8,287	29.3%	(17.1%)	28.8%	(17.3%)
2004	62,755	17,141	63,654	17,362	54.4%	106.7%	54.6%	109.5%
2005	94,438	17,204	96,449	17,462	50.5%	0.4%	51.5%	0.6%
2006	100,056	16,543	102,164	16,559	5.9%	(3.8%)	5.9%	(5.2%)
2007	108,707	16,549	111,023	16,729	8.6%	0.0%	8.7%	1.0%
2008	105,485	15,994	107,885	16,136	(3.0%)	(3.4%)	(2.8%)	(3.5%)
2009	97,388	16,364	100,022	16,397	(7.7%)	2.3%	(7.3%)	1.6%
2010	107,307	21,655	110,026	21,837	10.2%	32.3%	10.0%	33.2%
2011	117,130	20,977	119,501	21,259	9.2%	(3.1%)	8.6%	(2.6%)
2012	134,479	17,905	136,903	18,080	14.8%	(14.6%)	14.6%	(15.0%)
2013	148,323	18,783	150,595	18,978	10.3%	4.9%	10.0%	5.0%

PJM Day-Ahead, Monthly Average Supply

Figure 3-6 compares the day-ahead, monthly average hourly supply, including increment offers and up-to congestion transactions, of 2013 with those of 2012.

Figure 3-6 PJM day-ahead monthly average hourly supply: January 2012 through December 2013



Real-Time and Day-Ahead Supply

Table 3-12 presents summary statistics for 2012 and 2013 for day-ahead and real-time supply. The last two columns of Table 3-12 are the day-ahead supply minus the real-time supply. The first of these columns is the total day-ahead supply less the total real-time supply and the second of these columns is the total physical day-ahead generation less the total physical real-time generation. In 2013, up-to congestion transactions were 34.3 percent of the total day-ahead supply compared to 28.0 percent in 2012.

28 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

Table 3-12 Day-ahead and real-time supply (MWh): 2012 and 2013

		Day Ahead					Real Time		Day Ahead Less Real Time	
	Year	Generation	INC Offers	Up-to Congestion	Imports	Total Supply	Generation	Total Supply	Total Supply	Total Generation
Average	2012	90,134	6,000	38,344	2,424	136,903	88,708	94,083	42,820	1,426
	2013	91,593	5,131	51,598	2,273	150,595	89,769	94,833	55,763	1,825
Median	2012	88,404	5,976	37,015	2,381	135,826	86,513	91,920	43,907	1,891
	2013	90,767	5,099	51,992	2,249	150,475	88,721	93,518	56,957	2,046
Standard Deviation	2012	17,301	922	7,978	503	18,080	15,701	16,505	1,575	1,600
	2013	16,059	856	10,061	429	18,978	15,012	15,878	3,101	1,046
Peak Average	2012	100,130	6,348	37,347	2,612	146,437	97,134	103,097	43,340	2,996
	2013	101,479	5,369	52,246	2,374	161,469	98,622	104,192	57,276	2,857
Peak Median	2012	96,163	6,291	36,899	2,596	143,614	93,361	99,063	44,551	2,802
	2013	99,284	5,420	53,079	2,366	159,563	96,660	102,041	57,523	2,625
Peak Standard Deviation	2012	15,068	753	5,663	466	15,405	14,272	14,979	426	796
	2013	13,183	799	9,563	370	15,798	12,706	13,606	2,192	477
Off-Peak Average	2012	81,400	5,697	39,215	2,261	128,573	81,346	86,207	42,367	55
	2013	82,975	4,923	51,033	2,184	141,116	82,050	86,673	54,443	925
Off-Peak Median	2012	79,555	5,618	37,142	2,221	126,367	79,350	84,065	42,302	205
	2013	81,764	4,892	51,070	2,092	140,236	80,697	85,164	55,072	1,067
Off-Peak Standard Deviation	2012	14,103	950	9,467	476	16,012	12,951	13,468	2,544	1,152
	2013	13,105	849	10,444	456	16,239	12,378	12,944	3,295	727

Figure 3-7 shows the average hourly cleared volumes of day-ahead supply and real-time supply. The day-ahead supply consists of day-ahead generation, imports, increment offers and up-to congestion transactions. The real-time generation includes generation and imports.

Figure 3-7 Day-ahead and real-time supply (Average hourly volumes): 2013

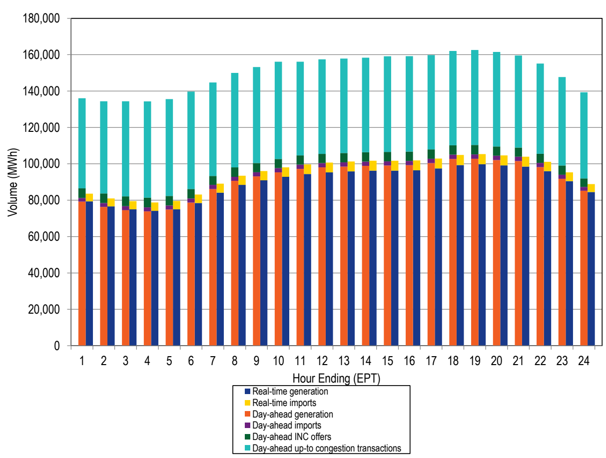


Figure 3-8 shows the difference between the day-ahead and real-time average daily supply in 2012 and 2013.

Figure 3-8 Difference between day-ahead and real-time supply (Average daily volumes): January 2012 through December of 2013

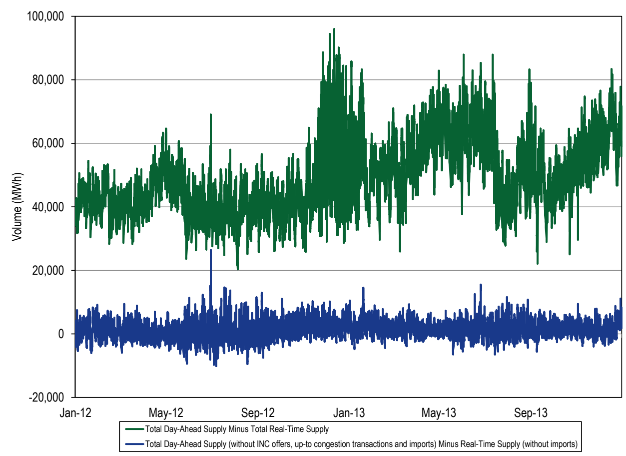
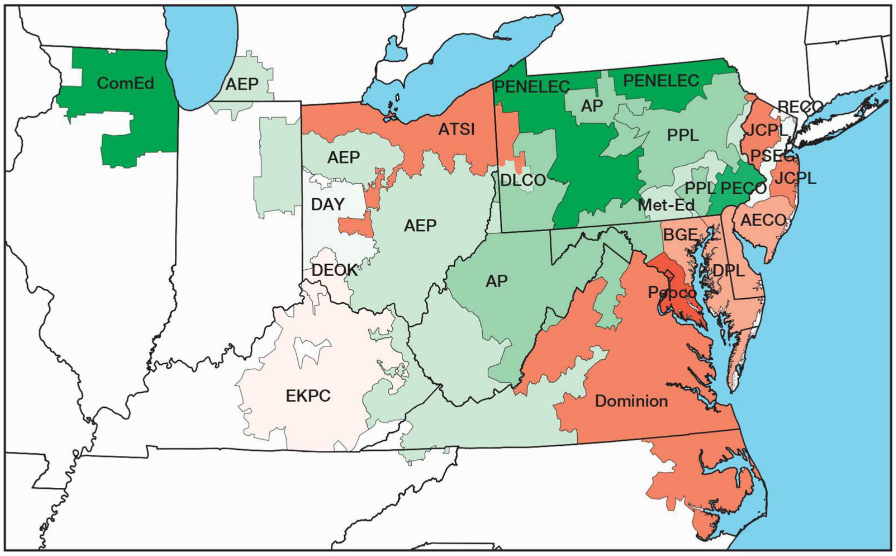


Figure 3-9 shows the difference between the PJM real-time generation and real-time load by zone in 2013. Table 3-13 shows the difference between the PJM real-time generation and real-time load by zone in 2012 and 2013. Figure 3-9 is color coded on a scale on which red shades represent zones that have 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.

Figure 3-9 Map of PJM real-time generation less real-time load by zone: 2013[29]



Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)
AECO	(8,178)	ComEd	28,686	DPL	(10,884)	PENELEC	26,357
AEP	3,653	DAY	308	EKPC	(1,455)	Pepco	(21,151)
AP	7,316	DEOK	(1,811)	JCPL	(11,867)	PPL	8,915
ATSI	(11,757)	DLCO	2,976	Met-Ed	4,847	PSEG	1,503
BGE	(10,401)	Dominion	(12,875)	PECO	19,935	RECO	(1,531)

Table 3-13 PJM real-time generation less real-time load by zone (GWh): 2012 and 2013

	Zonal Generation and Load (GWh)					
	2012			2013		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	2,003.5	10,655.9	(8,652.4)	2,219.5	10,397.8	(8,178.4)
AEP	142,723.2	131,002.1	11,721.0	133,130.2	129,477.6	3,652.6
AP	50,900.7	46,036.5	4,864.2	54,539.3	47,223.6	7,315.7
ATSI	57,934.8	66,653.6	(8,718.8)	55,061.7	66,818.8	(11,757.1)
BGE	20,796.6	32,422.2	(11,625.5)	21,794.6	32,196.1	(10,401.4)
ComEd	128,101.3	99,348.9	28,752.5	127,235.2	98,548.9	28,686.3
DAY	15,486.4	16,761.5	(1,275.1)	17,047.5	16,739.6	307.9
DEOK	19,913.4	26,523.2	(6,609.8)	24,845.3	26,656.0	(1,810.7)
DLCO	17,773.9	14,937.0	2,836.9	17,650.0	14,674.3	2,975.7
Dominion	76,717.5	91,713.0	(14,995.5)	80,988.9	93,863.4	(12,874.5)
DPL	8,425.1	18,240.5	(9,815.4)	7,575.3	18,459.1	(10,883.8)
EKPC	NA	NA	NA	5,629.8	7,085.0	(1,455.2)
JCPL	12,659.6	22,597.0	(9,937.5)	11,145.3	23,012.3	(11,867.0)
Met-Ed	20,973.5	14,996.9	5,976.6	19,937.3	15,090.7	4,846.5
PECO	61,033.8	39,794.6	21,239.2	60,062.2	40,127.2	19,935.0
PENELEC	38,185.2	17,103.0	21,082.2	43,582.3	17,225.2	26,357.1
Pepco	12,399.9	30,658.2	(18,258.3)	9,264.6	30,416.0	(21,151.4)
PPL	47,863.8	39,748.6	8,115.2	49,475.8	40,560.9	8,914.8
PSEG	45,316.4	43,589.6	1,726.8	45,189.5	43,686.4	1,503.0
RECO	0.0	1,520.2	(1,520.2)	0.0	1,530.8	(1,530.8)

Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

The PJM system load reflects the configuration of the entire RTO. The PJM Energy Market includes the Real-Time Energy Market and the Day-Ahead Energy Market. In this section, demand refers to the physical load and exports and in the Day-Ahead Energy Market also includes the virtual transactions, which include decrement bids and up-to congestion transactions.

The PJM system peak load for 2013 was 157,508 MW in the HE 1700 on July 18, 2013, which was 3,165 MW, or 2.1 percent, higher than the PJM peak load for 2012, which was 154,344 MW in the HE 1700 on July 17, 2012. The EKPC Transmission Zone accounted for 2,175 MW in the peak hour of 2013. The peak load excluding the EKPC

29 Zonal real-time generation data for the map and corresponding table is based on the zonal designation for every bus listed in the most current PJM LMP bus model, which can be found at <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/bus-model-updates.aspx>.

Transmission Zone was 155,333 MW, also occurring on July 18, 2013, HE 1700, an increase of 990 MW, or 0.6 percent.

Table 3-14 shows the coincident peak loads for the years 1999 through 2013.

Table 3-14 Actual PJM footprint peak loads: 1999 to 2013[30]

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Tue, July 06	14	51,689	NA	NA
2000	Wed, August 09	17	49,469	(2,220)	(4.3%)
2001	Thu, August 09	15	54,015	4,546	9.2%
2002	Wed, August 14	16	63,762	9,747	18.0%
2003	Fri, August 22	16	61,499	(2,263)	(3.5%)
2004	Tue, August 03	17	77,887	16,387	26.6%
2005	Tue, July 26	16	133,761	55,875	71.7%
2006	Wed, August 02	17	144,644	10,883	8.1%
2007	Wed, August 08	16	139,428	(5,216)	(3.6%)
2008	Mon, June 09	17	130,100	(9,328)	(6.7%)
2009	Mon, August 10	17	126,798	(3,302)	(2.5%)
2010	Tue, July 06	17	136,460	9,662	7.6%
2011	Thu, July 21	17	158,016	21,556	15.8%
2012	Tue, July 17	17	154,344	(3,672)	(2.3%)
2013 (with EKPC)	Thu, July 18	17	157,508	3,165	2.1%
2013 (without EKPC)	Thu, July 18	17	155,333	990	0.6%

Figure 3-10 shows the peak loads for the years 1999 through 2013.

Figure 3-10 PJM footprint calendar year peak loads: 1999 to 2013

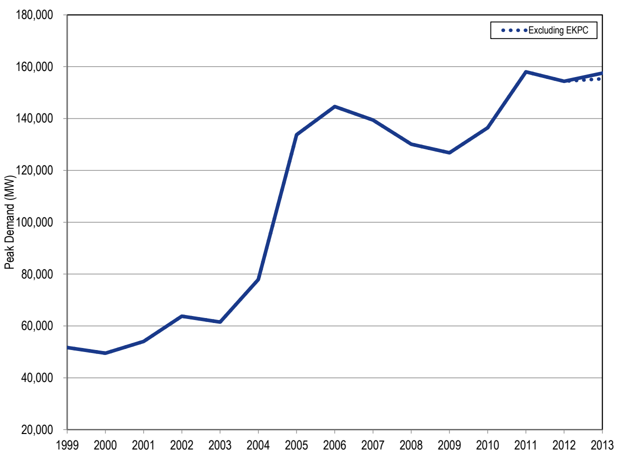
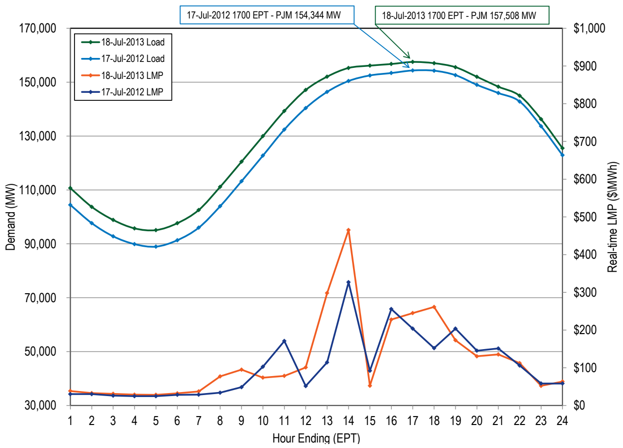


Figure 3-11 compares the peak load days in 2012 and 2013. In every hour on July 18, 2013, the average hourly real-time load was higher than the average hourly real-time load on July 17, 2012. The average hourly real-time LMP peaked at $465.18 on July 18, 2013 and peaked at $326.72 on July 17, 2012.

Figure 3-11 PJM peak-load comparison: Thursday, July 18, 2013, and Tuesday, July 17, 2012



Real-Time Demand

PJM average real-time load in 2013 increased by 1.5 percent from 2012, from 87,011 MW to 88,332 MW. The PJM average real-time load in 2013 would have increased by 0.6 percent from 2012, from 87,011 MW to 87,537 MW, if the EKPC Transmission Zone had not been included in the comparison.[31,32]

In the PJM Real-Time Energy Market, there are two types of demand:

- **Load.** The actual MWh level of energy used.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. A real-time export must have a valid OASIS reservation when offered, must have available ramp room to support the export, must be accompanied by a NERC e-Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Demand Duration

Figure 3-12 shows the hourly distribution of PJM real-time load plus exports for 2012 and 2013.[33]

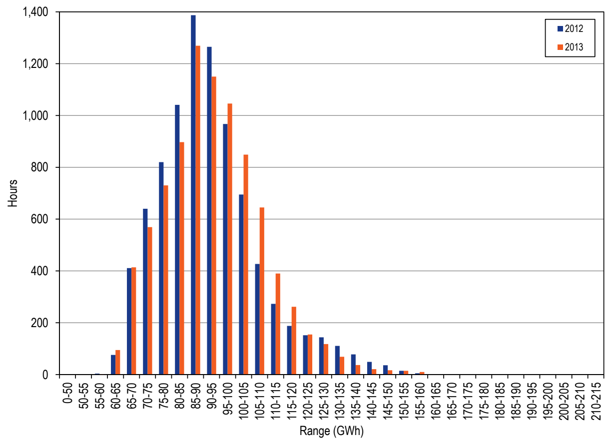
30 Peak loads shown are eMTR load. See the *MMU Technical Reference for the PJM Markets*, at "Load Definitions" for detailed definitions of load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

31 The EKPC Transmission Zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013.

32 Load data are the net MWh injections and withdrawals MWh at every load bus in PJM.

33 All real-time load data in Section 3, "Energy Market," "Market Performance: Load and LMP" are based on PJM accounting load. See the *Technical Reference for PJM Markets*, "Load Definitions," for detailed definitions of accounting load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Figure 3-12 Distribution of PJM real-time accounting load plus exports: 2012 and 2013[34,35]



PJM Real-Time, Average Load

Table 3-15 presents summary real-time demand statistics for each year 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.[36]

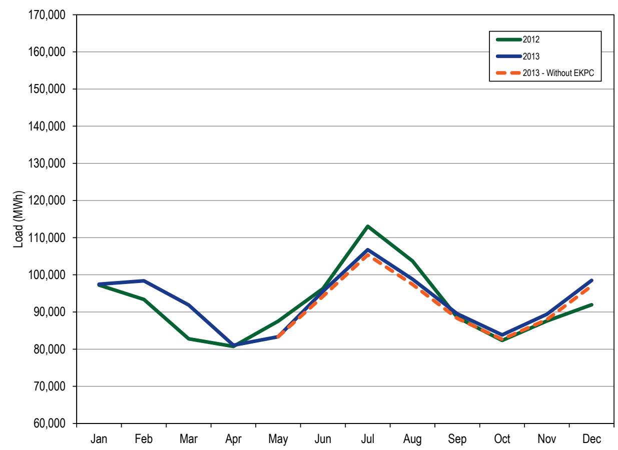
Table 3-15 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: 1998 through 2013[37,38]

	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Year	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
1998	28,578	5,511	NA	NA	NA	NA	NA	NA
1999	29,641	5,955	NA	NA	3.7%	8.1%	NA	NA
2000	30,113	5,529	31,341	5,728	1.6%	(7.2%)	NA	NA
2001	30,297	5,873	32,165	5,564	0.6%	6.2%	2.6%	(2.9%)
2002	35,776	7,976	37,676	8,145	18.1%	35.8%	17.1%	46.4%
2003	37,395	6,834	39,380	6,716	4.5%	(14.3%)	4.5%	(17.5%)
2004	49,963	13,004	54,953	14,947	33.6%	90.3%	39.5%	122.6%
2005	78,150	16,296	85,301	16,546	56.4%	25.3%	55.2%	10.7%
2006	79,471	14,534	85,696	15,133	1.7%	(10.8%)	0.5%	(8.5%)
2007	81,681	14,618	87,897	15,199	2.8%	0.6%	2.6%	0.4%
2008	79,515	13,758	86,306	14,322	(2.7%)	(5.9%)	(1.8%)	(5.8%)
2009	76,034	13,260	81,227	13,792	(4.4%)	(3.6%)	(5.9%)	(3.7%)
2010	79,611	15,504	85,518	15,904	4.7%	16.9%	5.3%	15.3%
2011	82,541	16,156	88,466	16,313	3.7%	4.2%	3.4%	2.6%
2012	87,011	16,212	92,135	16,052	5.4%	0.3%	4.1%	(1.6%)
2013	88,332	15,489	92,879	15,418	1.5%	(4.5%)	0.8%	(3.9%)

PJM Real-Time, Monthly Average Load

Figure 3-13 compares the real-time, monthly average hourly loads in 2013 with those in 2012.

Figure 3-13 PJM real-time monthly average hourly load: January 2012 through December 2013



PJM real-time load is significantly affected by temperature. Figure 3-14 compares the total PJM monthly heating and cooling degree days in 2013 with those in 2012.[39] The figure shows that in 2013, the heating degree days were higher, except October and November, and the cooling degree days were lower, except September and October, than in the corresponding months of 2012.

34 Each range on the horizontal axis excludes the start value and includes the end value.

35 The 2012 data used in the version of this figure in the *2012 State of the Market Report for PJM* have been updated by PJM and the updates are included in this figure.

36 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.

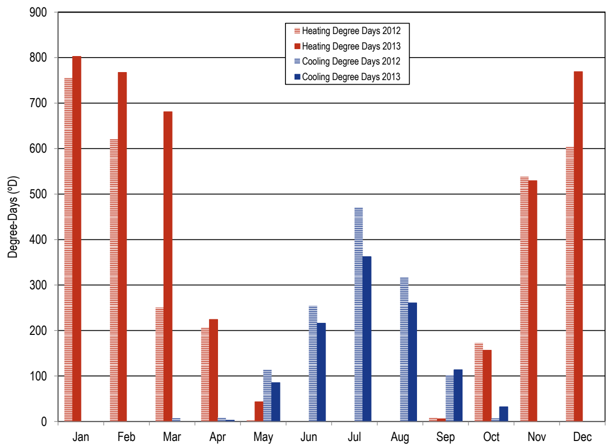
37 The data used in the version of this table in the *2012 State of the Market Report for PJM* have been updated by PJM and the updates are reflected in this table.

38 The export data in this table are not available before June 1, 2000. The export data in 2000 are for the last six months of 2000.

39 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees 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).

Heating and cooling degree days are calculated by weighting the temperature at each weather station in the individual transmission zones using weights provided by PJM in Manual 19. Then the temperature is weighted by the real-time zonal accounting load for each transmission zone. After calculating an average daily temperature across PJM, the heating and cooling degree formulas are used to calculate the daily heating and cooling degree days, which are summed for monthly reporting. 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, SDF, TOL and WAL.

Figure 3-14 PJM heating and cooling degree days: 2012 and 2013



Day-Ahead Demand

PJM average day-ahead demand, including DECs and up-to congestion transactions, in 2013 increased by 10.1 percent from 2012, from 131,612 MW to 144,858 MW. The PJM average day-ahead demand, including DECs and up-to congestion transactions, would have increased 9.4 percent from 2012, from 131,612 MW to 143,962 MW, if the EKPC Transmission Zone had not been included in the comparison.

The day-ahead demand growth was 573.3 percent higher than the real-time load growth because of the continued growth of up-to congestion transactions. If 2013 up-to congestion transactions had been held to 2012 levels, the day-ahead demand would have decreased 0.01 percent instead of increasing 10.1 percent. The day-ahead demand growth would have been 100.7 percent lower than the real-time load growth.

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

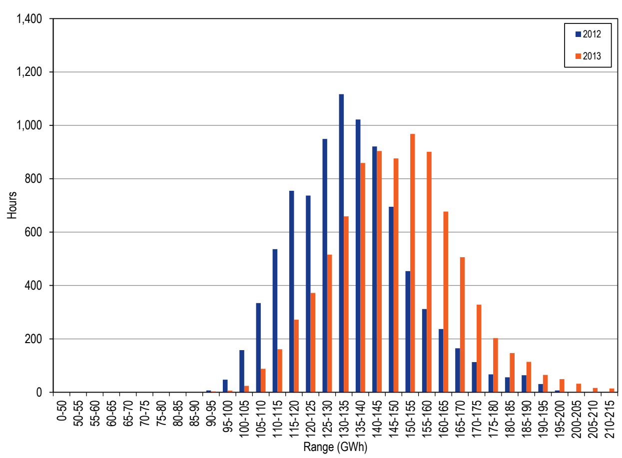
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A DEC can be submitted by any market participant.
- **Up-to Congestion Transaction.** 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. An up-to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. An export must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An export energy transaction that clears the Day-Ahead Energy Market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an export energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the Real-Time Energy Market scheduling process.

PJM day-ahead demand is the hourly total of the five types of cleared demand bids.

PJM Day-Ahead Demand Duration

Figure 3-15 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up-to congestion transactions, and exports for 2012 and 2013.

Figure 3-15 Distribution of PJM day-ahead demand plus exports: 2012 and 2013[40]



40 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Day-Ahead, Average Demand

Table 3-16 presents summary day-ahead demand statistics for each year of the 14-year period 2000 to 2013.[41]

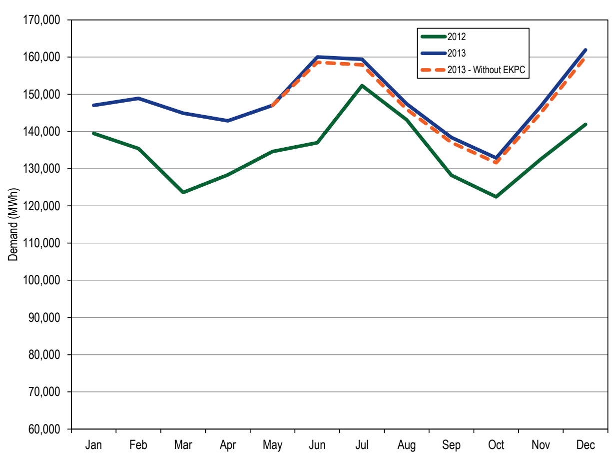
Table 3-16 PJM day-ahead average demand and day-ahead average hourly demand plus average hourly exports: 2000 through 2013

	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
Year	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2000	33,039	6,852	33,411	6,757	NA	NA	NA	NA
2001	33,370	6,562	33,757	6,431	1.0%	(4.2%)	1.0%	(4.8%)
2002	42,305	10,161	42,413	10,208	26.8%	54.9%	25.6%	58.7%
2003	44,674	7,841	44,807	7,811	5.6%	(22.8%)	5.6%	(23.5%)
2004	62,101	16,654	63,455	17,730	39.0%	112.4%	41.6%	127.0%
2005	93,534	17,643	96,447	17,952	50.6%	5.9%	52.0%	1.3%
2006	98,527	16,723	101,592	17,197	5.3%	(5.2%)	5.3%	(4.2%)
2007	105,503	16,686	108,932	17,030	7.1%	(0.2%)	7.2%	(1.0%)
2008	101,903	15,871	105,368	16,119	(3.4%)	(4.9%)	(3.3%)	(5.3%)
2009	94,941	15,869	98,094	15,999	(6.8%)	(0.0%)	(6.9%)	(0.7%)
2010	103,937	21,358	108,069	21,640	9.5%	34.6%	10.2%	35.3%
2011	113,866	20,708	117,681	20,929	9.6%	(3.0%)	8.9%	(3.3%)
2012	131,612	17,421	134,947	17,527	15.6%	(15.9%)	14.7%	(16.3%)
2013	144,858	18,489	148,132	18,570	10.1%	6.1%	9.8%	5.9%

PJM Day-Ahead, Monthly Average Demand

Figure 3-16 compares the day-ahead, monthly average hourly demand, including decrement bids and up-to congestion transactions, of 2013 with those of 2012.

Figure 3-16 PJM day-ahead monthly average hourly demand: January 2012 through December 2013



41 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

Real-Time and Day-Ahead Demand

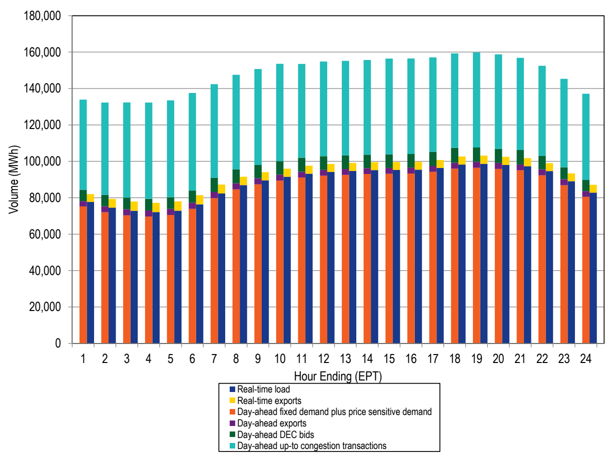
Table 3-17 presents summary statistics for 2012 and 2013 day-ahead and real-time demand. The last two columns of Table 3-17 are the day-ahead demand minus the real-time demand. The first such column is the total day-ahead demand less the total real-time demand and the second such column is the total physical day-ahead load (fixed demand plus price sensitive demand) less the physical real-time load.

Table 3-17 Cleared day-ahead and real-time demand (MWh): 2012 and 2013[42]

		Day Ahead						Real Time		Day Ahead Less Real Time	
	Year	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Total Demand	Total Load
Average	2012	84,112	720	8,435	38,344	3,335	134,947	87,011	92,135	42,812	(2,179)
	2013	84,859	1,199	7,202	51,598	3,273	148,132	88,332	92,879	55,253	(2,275)
Median	2012	82,422	692	8,169	37,015	3,281	133,896	85,018	90,024	43,872	(1,903)
	2013	83,734	1,229	6,930	51,992	3,231	148,008	87,072	91,572	56,436	(2,108)
Standard Deviation	2012	15,855	143	1,818	7,978	697	17,527	16,212	16,052	1,476	(214)
	2013	14,789	245	1,438	10,061	662	18,570	15,489	15,418	3,152	(455)
Peak Average	2012	93,339	771	9,421	37,347	3,354	144,232	96,186	100,899	43,333	(2,076)
	2013	94,149	1,295	7,821	52,246	3,276	158,788	97,624	101,993	56,795	(2,179)
Peak Median	2012	89,430	741	9,174	36,899	3,322	141,439	92,192	96,887	44,552	(2,021)
	2013	92,358	1,347	7,516	53,079	3,232	157,103	95,465	99,864	57,240	(1,761)
Peak Standard Deviation	2012	13,984	145	1,671	5,663	666	14,976	14,404	14,604	372	(275)
	2013	12,265	257	1,424	9,563	667	15,479	13,105	13,202	2,276	(583)
Off-Peak Average	2012	76,049	676	7,574	39,215	3,318	126,834	78,994	84,478	42,356	(2,268)
	2013	76,759	1,115	6,663	51,033	3,271	138,841	80,232	84,933	53,908	(2,357)
Off-Peak Median	2012	73,982	656	7,260	37,142	3,251	124,781	76,897	82,408	42,373	(2,260)
	2013	75,503	1,144	6,422	51,070	3,230	138,112	78,751	83,509	54,602	(2,104)
Off-Peak Standard Deviation	2012	12,680	125	1,472	9,467	723	15,445	13,168	13,067	2,378	(363)
	2013	11,721	199	1,215	10,444	658	15,854	12,588	12,548	3,306	(668)

Figure 3-17 shows the average hourly cleared volumes of day-ahead demand and real-time demand. The day-ahead demand includes day-ahead load, day-ahead exports, decrement bids and up-to congestion transactions. The real-time demand includes real-time load and real-time exports.

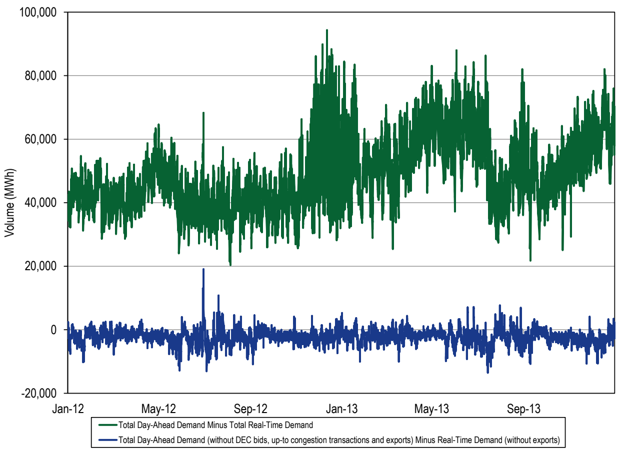
Figure 3-17 Day-ahead and real-time demand (Average hourly volumes): 2013



42 The data used in the version of this table in the *2012 State of the Market Report for PJM* have been updated by PJM and the updates are accounted for in this table.

Figure 3-18 shows the difference between the day-ahead and real-time average daily demand in 2012 and 2013.

Figure 3-18 Difference between day-ahead and real-time demand (Average daily volumes): January 2012 through December of 2013



Supply and Demand: 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 generating less power from owned plants and/or purchasing less power under bilateral contracts than required 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 3-18 shows the monthly average share of real-time load served by self-supply, bilateral contracts and spot purchase in 2012 and 2013 based on parent company. For 2013, 10.6 percent of real-time load was supplied by bilateral contracts, 25.0 percent by spot market purchase and 64.4 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased 1.6 percentage points, reliance on spot supply increased by 1.8 percentage points and reliance on self-supply decreased by 3.3 percentage points.

Table 3-18 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%	10.7%	24.2%	65.1%	1.3%	0.4%	(1.6%)
May	8.6%	23.5%	67.9%	10.9%	25.4%	63.6%	2.4%	1.9%	(4.3%)
Jun	8.7%	22.3%	69.0%	10.7%	25.0%	64.3%	2.0%	2.7%	(4.8%)
Jul	8.0%	22.7%	69.3%	10.2%	25.2%	64.7%	2.2%	2.5%	(4.6%)
Aug	8.5%	23.6%	67.9%	10.2%	24.5%	65.3%	1.7%	0.8%	(2.6%)
Sep	9.1%	24.4%	66.5%	10.1%	24.2%	65.7%	1.1%	(0.2%)	(0.9%)
Oct	9.6%	25.5%	64.9%	11.1%	28.2%	60.7%	1.5%	2.7%	(4.2%)
Nov	9.9%	23.9%	66.3%	10.6%	27.2%	62.2%	0.7%	3.3%	(4.0%)
Dec	10.2%	22.6%	67.3%	11.3%	27.1%	61.7%	1.1%	4.5%	(5.6%)
Annual	9.0%	23.2%	67.8%	10.6%	25.0%	64.4%	1.6%	1.8%	(3.3%)

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 supply in the day-ahead analysis and virtual demand is treated as demand in the day-ahead analysis.

Table 3-19 Monthly average percentage of day-ahead self-supply demand, bilateral supply demand, and spot-supply demand 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%	7.1%	23.1%	69.8%	0.5%	0.3%	(0.8%)
May	6.6%	22.7%	70.7%	7.8%	23.5%	68.7%	1.2%	0.8%	(2.0%)
Jun	7.7%	20.7%	71.6%	8.2%	23.8%	68.0%	0.5%	3.1%	(3.5%)
Jul	5.9%	22.0%	72.0%	8.0%	24.1%	67.9%	2.0%	2.1%	(4.1%)
Aug	6.4%	22.5%	71.0%	8.1%	23.9%	68.0%	1.7%	1.4%	(3.1%)
Sep	6.5%	23.9%	69.6%	7.8%	23.9%	68.3%	1.3%	(0.0%)	(1.3%)
Oct	6.6%	25.2%	68.2%	9.8%	29.0%	61.3%	3.2%	3.7%	(6.9%)
Nov	6.9%	22.7%	70.5%	9.3%	29.1%	61.7%	2.4%	6.4%	(8.8%)
Dec	7.0%	21.2%	71.8%	9.9%	25.6%	64.5%	2.9%	4.4%	(7.4%)
Annual	6.7%	22.3%	71.0%	8.0%	24.5%	67.5%	1.4%	2.2%	(3.6%)

The PJM system's reliance on self-supply, bilateral contracts, and spot purchases to meet day-ahead demand (cleared fixed-demand, price-sensitive load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve demand in the Day-Ahead Energy Market for each hour. Table 3-19 shows the monthly average share of day-ahead demand served by self-supply, bilateral contracts and spot purchases in 2012 and 2013, based on parent companies. For 2013, 8.0 percent of day-ahead demand was supplied by bilateral contracts, 24.5 percent by spot market purchases, and 67.5 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased by 1.4 percentage points, reliance on spot supply increased by 2.2 percentage points, and reliance on self-supply decreased by 3.6 percentage points.

Market Behavior

Offer Capping for Local Market Power

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 3-20. The offer capping percentages shown in Table 3-20 include units that are committed to provide constraint relief whose owners failed the TPS test in the Energy Market, excluding offer capping for reliability reasons.

Table 3-20 Offer-capping statistics – Energy only: 2009 to 2013

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2009	0.4%	0.1%	0.1%	0.0%
2010	1.2%	0.4%	0.2%	0.1%
2011	0.6%	0.2%	0.0%	0.0%
2012	0.8%	0.4%	0.1%	0.1%
2013	0.4%	0.2%	0.1%	0.0%

Table 3-21 shows the offer capping percentages including units committed to provide constraint relief as well as units committed to provide black start service and reactive support. The units that are committed and offer capped for reliability reasons have been steadily increasing since 2011. Before 2011, the units that ran to provide black start service and reactive support were generally economic in the energy market. Since 2011, the percentage of hours when these units were not economic (and are therefore committed on their cost schedule for reliability reasons) has steadily increased.

Table 3-21 Offer-capping statistics for energy and reliability: 2009 to 2013

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2009	0.4%	0.1%	0.1%	0.0%
2010	1.2%	0.4%	0.2%	0.1%
2011	0.7%	0.2%	0.0%	0.0%
2012	1.7%	1.0%	0.9%	0.5%
2013	2.9%	2.4%	3.2%	2.1%

Table 3-22 presents data on the frequency with which units were offer capped in 2012 and 2013 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market.

Table 3-22 Real-time offer-capped unit statistics: 2012 and 2013[43]

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:		Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2013	0	0	0	0	0	0
	2012	0	1	0	1	1	1
80% and < 90%	2013	0	0	0	1	1	3
	2012	0	1	1	0	1	2
75% and < 80%	2013	0	0	0	0	1	2
	2012	0	0	0	0	0	2
70% and < 75%	2013	0	0	1	0	0	3
	2012	0	0	0	0	1	2
60% and < 70%	2013	0	0	0	0	0	4
	2012	0	0	0	1	1	9
50% and < 60%	2013	0	0	0	0	0	9
	2012	3	0	1	0	1	6
25% and < 50%	2013	0	3	3	1	7	44
	2012	6	1	0	3	2	45
10% and < 25%	2013	2	0	0	4	3	46
	2012	2	2	0	3	12	58

Table 3-22 shows that no units were offer capped for 90 percent or more of their run hours in 2013.

Offer Capping for Local Market Power

In 2013, the AECO, AEP, ATSI, BGE, ComEd, Dominion, DPL, PECO, PENELEC, Pepco, PPL and PSEG control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The AP, DAY, DEOK, DLCO, JCPL, Met-Ed, and RECO control zones did not have constraints binding for 100 or more hours in 2013. Table 3-23 shows that BGE, ComEd, Dominion and PSEG were the only control zones with 100 or more hours of congestion in every year from 2009 through 2013.

Table 3-23 Numbers of hours when control zones experienced congestion for 100 or more hours: 2009 through 2013

	2009	2010	2011	2012	2013
AECO	149	172	234	NA	208
AEP	2,449	1,941	2,032	NA	873
AP	4,486	5,538	962	206	NA
ATSI	NA	NA	NA	208	135
BGE	456	940	807	2,196	880
ComEd	2,626	3,310	1,134	3,467	2,760
DEOK	NA	NA	NA	109	NA
DLCO	312	260	103	209	NA
Dominion	702	1,246	1,052	1,020	981
DPL	NA	244	NA	1,070	426
Met-Ed	NA	360	162	NA	NA
PECO	494	NA	483	386	488
PENELEC	103	568	NA	NA	176
Pepco	298	NA	NA	143	145
PPL	176	118	NA	NA	294
PSEG	442	549	613	913	2,014

Competitive conditions in the Real-Time Energy Market associated with each of the frequently binding constraints were analyzed using the three pivotal supplier results for 2013.[44] The three pivotal supplier (TPS) 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 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 3-24 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 transfer interface constraints.

43 This table was modified from the previous State of the Market report to include only units that are offer capped for failing the TPS test in the Real-Time Energy Market.

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

Table 3-24 Three pivotal supplier test details for interface constraints: 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	279	313	13	2	11
	Off Peak	205	282	12	3	9
AEP - DOM	Peak	167	167	5	0	5
	Off Peak	153	189	5	0	5
AP South	Peak	306	464	10	1	9
	Off Peak	330	506	10	1	9
ATSI	Peak	321	717	15	12	3
	Off Peak	0	0	0	0	0
BC/PEPCO	Peak	204	415	11	5	6
	Off Peak	262	469	10	5	5
Bedington - Black Oak	Peak	126	279	13	6	7
	Off Peak	181	367	13	6	7
Cleveland	Peak	97	119	2	0	2
	Off Peak	0	0	0	0	0
Eastern	Peak	488	449	13	1	12
	Off Peak	0	0	0	0	0
PL North	Peak	37	99	1	0	1
	Off Peak	151	321	2	0	2
Western	Peak	470	530	14	3	11
	Off Peak	1,295	1,800	20	6	14

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 3-25 provides, for the identified interface constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping uncommitted units.

Table 3-25 Summary of three pivotal supplier tests applied for interface constraints: 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	766	57	7%	19	2%	33%
	Off Peak	705	52	7%	16	2%	31%
AEP - DOM	Peak	133	4	3%	0	0%	0%
	Off Peak	31	2	6%	0	0%	0%
AP South	Peak	5,771	226	4%	48	1%	21%
	Off Peak	4,412	124	3%	27	1%	22%
ATSI	Peak	144	4	3%	0	0%	0%
	Off Peak	0	0	0%	0	0%	0%
Bedington - Black Oak	Peak	316	3	1%	0	0%	0%
	Off Peak	95	2	2%	0	0%	0%
BC/PEPCO	Peak	910	48	5%	7	1%	15%
	Off Peak	819	33	4%	8	1%	24%
Cleveland	Peak	108	6	6%	3	3%	50%
	Off Peak	0	0	0%	0	0%	0%
Eastern	Peak	26	0	0%	0	0%	0%
	Off Peak	0	0	0%	0	0%	0%
PL North	Peak	5	0	0%	0	0%	0%
	Off Peak	212	0	0%	0	0%	0%
Western	Peak	404	14	3%	7	2%	50%
	Off Peak	254	7	3%	5	2%	71%

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

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.[45] 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. The markup index does not measure the impact of unit markup on total LMP.

Real-Time Markup

Table 3-26 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category. For convenience, the marginal units are grouped into one of seven categories based on their respective offer prices. The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point. In 2013, 93.0 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.04. The data shows that despite the fact that markup had a negligible impact on LMP in 2013, some marginal units do have substantial markups.

Table 3-26 Average, real-time marginal unit markup index (By price category): 2012 and 2013

	2012			2013		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.09)	($3.25)	31.3%	(0.01)	($3.27)	17.8%
$25 to $50	(0.05)	($2.67)	56.5%	(0.01)	($1.23)	65.3%
$50 to $75	0.05	$1.23	4.8%	(0.01)	($3.90)	8.4%
$75 to $100	0.28	$24.24	0.7%	0.04	($1.50)	1.5%
$100 to $125	0.23	$23.67	0.5%	0.10	$9.85	0.7%
$125 to $150	0.20	$27.69	0.2%	0.04	$4.98	1.7%
>= $150	0.04	$9.40	5.9%	0.03	$7.21	4.5%

Day-Ahead Markup

Table 3-27 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. In 2013, 99.0 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.00. The data shows that despite the fact that markup had a negligible impact on LMP in 2013, some marginal units do have substantial markups.

Table 3-27 Average marginal unit markup index (By offer price category): 2012 and 2013

	2012			2013		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.08)	($2.69)	29.5%	(0.07)	($1.78)	19.2%
$25 to $50	(0.05)	($2.43)	67.3%	(0.04)	($2.40)	75.2%
$50 to $75	0.09	$4.20	2.7%	0.00	($2.46)	4.6%
$75 to $100	0.45	$36.22	0.1%	0.08	$6.63	0.4%
$100 to $125	0.00	$0.00	0.0%	0.00	$0.00	0.1%
$125 to $150	(0.06)	($8.33)	0.1%	0.00	$0.00	0.0%
>= $150	0.03	$4.84	0.2%	0.75	$118.80	0.0%

Frequently Mitigated Units and Associated Units

An FMU is a frequently mitigated unit. The results reported here include units that were mitigated for any reason, including both structural market power in the energy market and units called on for reliability reasons, including reactive and black start service.

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 for 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 for 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.[46] These categories are designated Tier 1, Tier 2 and Tier 3.[47,48]

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 based on the number of run-hours the unit is offer capped. For example, if a generating station had two identical units with identical electrical impacts on the system, one of

45 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.

46 OA, Schedule 1 § 6.4.2.

47 114 FERC ¶ 61, 076 (2006).

48 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).

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

FMUs and AUs are designated monthly, and a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[49]

Table 3-28 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 2013. Of the 112 units eligible in at least one month during 2013, 22 units (19.6 percent) were FMUs or AUs for all twelve months, and 10 units (8.9 percent) qualified in only one month of 2013.

Table 3-28 Frequently mitigated units and associated units total months eligible: 2012 and 2013

	FMU & AU Count	
Number of Months Adder-Eligible	2012	2013
1	25	10
2	12	22
3	4	14
4	9	10
5	2	5
6	4	8
7	14	7
8	16	3
9	15	1
10	5	2
11	2	8
12	25	22
Total	133	112

Figure 3-19 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 December 31, 2013, there have been 341 unique units that have qualified for an FMU adder in at least one month. Of these 341 units, no unit qualified for an adder in all potential months. Two units qualified in 95 of the 96 possible months, and 103 of the 341 units (30.2 percent) have qualified for an adder in more than half of the possible months.

Figure 3-19 Frequently mitigated units and associated units total months eligible: February, 2006 through December, 2013

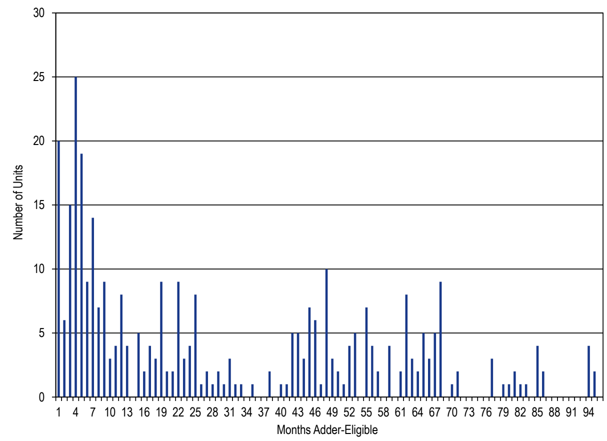


Table 3-29 shows, by month, the number of FMUs and AUs in 2012 and 2013. For example, in January 2013, there were 18 FMUs and AUs in Tier 1, 17 FMUs and AUs in Tier 2, and 10 FMUs and AUs in Tier 3.

Table 3-29 Number of frequently mitigated units and associated units (By month): 2012 and 2013

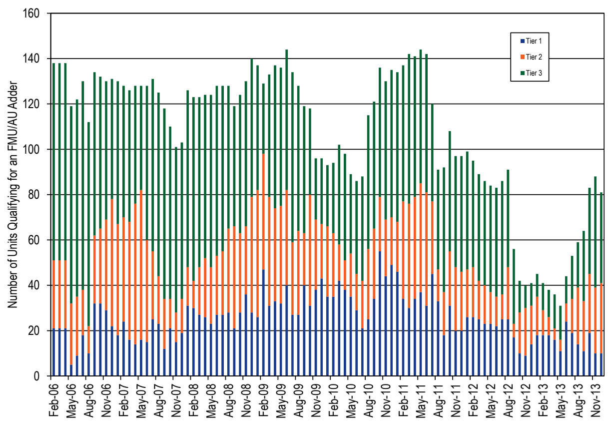
	FMUs and AUs							
	2012				2013			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	26	21	52	99	18	17	10	45
February	26	22	47	95	18	11	12	41
March	25	17	47	89	18	8	12	38
April	23	17	46	86	16	5	15	36
May	23	14	47	84	11	5	15	31
June	22	13	48	83	24	8	12	44
July	25	11	50	86	19	15	19	53
August	25	23	43	91	14	25	20	59
September	17	6	33	56	11	22	31	64
October	10	18	14	42	19	26	38	83
November	9	21	10	40	10	29	49	88
December	14	17	10	41	10	31	40	81

Figure 3-20 shows the total number of FMUs and AUs that qualified for an adder since the inception of the business rule in February 2006. The reduction in the total number of units qualifying for an FMU or AU adder in 2012 resulted from the decrease in congestion, which was in turn the result of changes in fuel costs, changes in the generation mix and changes in system topology. The increase in the total number of units

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

qualifying for an FMU or AU adder in 2013 was the result of modifications to commitment of black start and reactive units in the Day-Ahead Energy Market. In September 2012, PJM began to schedule units in the Day-Ahead Energy Market for black start and reactive that otherwise would not clear the market based on economics. Whenever these units are scheduled in the Day-Ahead Energy Market for black start and reactive, they are offer capped for all run hours in day ahead and real time. As FMU status is determined on a rolling 12-month period, this change started to affect the number of eligible FMU units in 2013.

Figure 3-20 Frequently mitigated units and associated units (By month): February, 2006 through December, 2013



The PJM Tariff defines offer capped units as those capped to maintain system reliability as a result of limits on transmission capability.[50] Offer capping for providing black start service does not meet this criterion. The MMU recommends that black start units not be given FMU status under the current rules.

The goal of the FMU adders was to ensure that units that were offer capped for most of their run hours could cover their going forward or avoidable costs (also known as ACR in the capacity market). The relevant units were all CTs, typically running less than 500 hours per year and the adders were specifically designed to cover ACR for such units. The FMU adders were not designed for baseload units like those providing reactive service. If the FMU adders are not eliminated, adders must be specifically designed for such baseload units.

The FMU adder was filed with FERC in 2005, and approved effective February 2006.[51] The goal, in 2005, was to ensure that units that were offer capped for most of their run hours could cover their going forward or avoidable costs (also known as ACR in the capacity market). That function became unnecessary with the introduction of the RPM capacity market design in 2007. Under the RPM design, units can make offers in the capacity market that include their ACR net of net revenues. Thus if there is a shortfall in ACR recovery, that shortfall is included in the RPM offer. If the unit clears in RPM, it covers its shortfall in ACR costs. If the unit does not clear, then the market result means that PJM can provide reliability without the unit and no additional revenue is needed.

The MMU recommends the elimination of FMU and AU adders. Since the implementation of FMU adders, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007, and 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. This recommendation is currently being evaluated in the PJM stakeholder process.

If an FMU rule were to remain, it should include a requirement that no unit receive an FMU adder if unit net revenues cover unit ACR. In 2013, of the 112 units that received FMU payments in 2013, 28 units did not cover ACR. Of those 28 units, 22 units are scheduled to retire. (Table 3-30.)

Table 3-30 Frequently mitigated units at risk of retirement

	No. of Units	MW
Units that received FMU payments in 2013	112	14,763
FMUs that did not cover ACR in 2013	28	5,342
FMUs that did not cover ACR in 2013 that are scheduled to retire	22	3,908
FMUs at risk of retirement	6	1,434

50 PJM OATT, 6.4 Offer Price Caps., (February 25, 2014), p. 1909.

51 110 FERC ¶ 61,053 (2005).

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 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, up-to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. Increment offers and decrement bids may be submitted at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. Up-to congestion transactions may be submitted between any two buses eligible for UTCs.[52] Import and export transactions may be submitted at any interface pricing point, where an import looks like a virtual offer that is injected into PJM and an export looks like a virtual bid that is withdrawn from PJM.

Figure 3-21 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve of imports, the system aggregate supply curve without increment offers and imports, the system aggregate supply curve with increment offers, and the system aggregate supply curve with increment offers and imports for an example day in 2013.

Figure 3-21 PJM day-ahead aggregate supply curves: 2013 example day

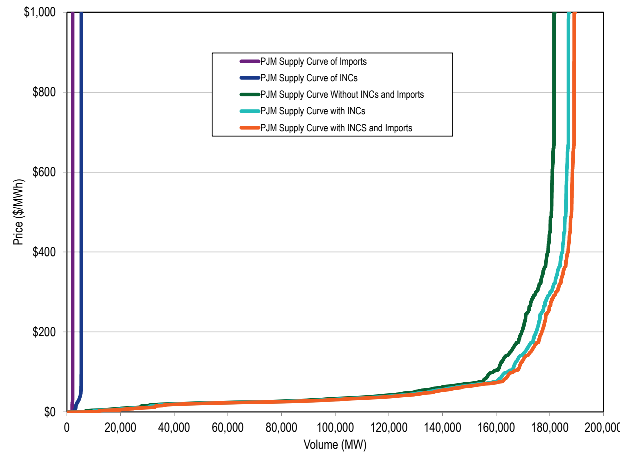


Table 3-31 shows the average hourly number of increment offers and decrement bids and the average hourly MW for 2012 and 2013. In 2013, the average hourly submitted and cleared increment offer MW decreased 23.4 and 14.5 percent, and the average hourly submitted and cleared decrement bid MW decreased 18.0 and 14.6 percent, compared to 2012.

52 Market participants were required to specify an interface pricing point as the source for imports, an interface pricing point as the sink for exports or an interface pricing point as both the source and sink for transactions wheeling through PJM. On November 1, 2012, PJM eliminated this requirement. For the list of eligible sources and sinks for up-to congestion transactions, see www.pjm.com "*OASIS-Source-Sink-Link.xls*,"<http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>.

Table 3-31 Hourly average number of cleared and submitted INCs, DECs by month: 2012 and 2013[53]

	Increment Offers				Decrement Bids			
Year	Average Cleared MW	Average Submitted MW	Average Cleared Number	Average Submitted Number	Average Cleared MW	Average Submitted MW	Average Cleared Number	Average Submitted Number
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	6,000	8,418	81	310	8,435	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 Apr	5,329	6,179	56	108	6,595	7,732	63	145
2013 May	5,415	6,651	57	130	7,036	8,803	74	185
2013 Jun	5,489	7,031	64	187	7,671	9,768	88	258
2013 Jul	5,374	6,710	60	173	7,566	9,786	89	267
2013 Aug	4,633	6,169	62	179	6,819	8,295	78	195
2013 Sep	4,262	5,464	60	191	6,646	8,400	82	233
2013 Oct	4,375	5,642	70	215	6,694	8,899	93	287
2013 Nov	4,906	6,803	81	304	7,202	10,200	105	386
2013 Dec	4,803	6,123	75	278	7,700	10,650	98	393
2013 Annual	5,131	6,451	65	182	7,202	9,088	83	239

In 2013, up-to congestion transactions continued to displace increment offers and decrement bids. Table 3-32 shows the average hourly number of up-to congestion transactions and the average hourly MW for 2012 and 2013. In 2013, the average hourly up-to congestion submitted MW increased 46.3 percent and cleared MW increased 34.6 percent, compared to 2012.

53 In prior versions of this table, the annual averages were the average of the monthly averages. In this table, the annual averages and the monthly averages are the averages of the hourly values.

Table 3-32 Hourly average of cleared and submitted up-to congestion bids by month: 2012 and 2013[54]

Up-to Congestion					
Year		Average Cleared MW	Average Submitted MW	Average Cleared Number	Average Submitted Number
2012	Jan	37,469	102,762	805	1,950
2012	Feb	37,132	106,741	830	2,115
2012	Mar	35,969	105,364	866	2,227
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	40,443	143,654	1,327	3,928
2012	Dec	45,536	176,660	1,681	5,145
2012	Annual	38,346	119,817	1,034	2,804
2013	Jan	44,844	157,229	1,384	4,205
2013	Feb	46,351	144,066	1,419	3,862
2013	Mar	49,003	163,178	1,467	3,745
2013	Apr	57,938	193,366	1,683	4,229
2013	May	59,700	203,521	1,679	4,754
2013	Jun	60,210	229,912	1,984	5,997
2013	Jul	49,674	201,630	1,658	5,300
2013	Aug	44,765	157,748	1,477	3,923
2013	Sep	45,412	136,813	1,408	3,507
2013	Oct	45,918	145,026	1,705	4,267
2013	Nov	54,643	171,439	2,108	5,365
2013	Dec	60,588	197,092	2,204	5,948
2013	Annual	51,598	175,255	1,682	4,596

Table 3-33 shows the average hourly number of import and export transactions and the average hourly MW for 2012 and 2013. In 2013, the average hourly submitted and cleared import transaction MW decreased 6.5 and 6.3 percent, and the average hourly submitted and cleared export transaction MW decreased 1.4 and 1.9 percent, compared to 2012.

54 In prior versions of this table, the annual averages were averages of the monthly averages. In this table, the annual averages and the monthly averages are averages of the hourly values.

Table 3-33 Hourly average number of cleared and submitted import and export transactions by month: 2012 and 2013

		Imports				Exports			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Number	Average Submitted Number	Average Cleared MW	Average Submitted MW	Average Cleared Number	Average Submitted Number
2012	Jan	1,962	2,269	11	15	3,746	3,763	22	22
2012	Feb	2,467	2,585	14	15	3,825	3,854	20	21
2012	Mar	2,268	2,305	12	13	2,946	2,981	21	21
2012	Apr	2,496	2,525	12	13	2,887	2,917	19	19
2012	May	2,795	2,928	13	15	2,754	2,767	19	19
2012	Jun	2,542	2,636	11	13	2,852	2,878	17	17
2012	Jul	2,633	2,781	13	15	3,743	3,769	22	23
2012	Aug	2,846	2,900	15	16	3,871	3,918	23	23
2012	Sep	2,089	2,131	11	11	3,488	3,494	21	21
2012	Oct	2,562	2,614	12	13	3,525	3,529	21	21
2012	Nov	2,436	2,545	11	12	2,934	2,947	18	18
2012	Dec	1,994	2,034	10	11	3,446	3,448	21	21
2012	Annual	2,424	2,521	12	14	3,335	3,356	20	20
2013	Jan	2,071	2,177	10	11	3,278	3,293	21	21
2013	Feb	2,098	2,244	11	13	3,275	3,288	19	19
2013	Mar	1,997	2,097	12	13	3,326	3,329	18	18
2013	Apr	2,004	2,097	12	13	2,691	2,691	16	16
2013	May	2,160	2,316	12	13	2,824	2,838	18	19
2013	Jun	2,712	2,818	15	16	3,420	3,507	19	20
2013	Jul	2,930	3,019	15	16	3,621	3,720	19	20
2013	Aug	2,577	2,656	13	15	3,734	3,766	20	20
2013	Sep	2,089	2,135	9	10	3,561	3,567	19	19
2013	Oct	2,191	2,216	10	10	3,215	3,225	18	18
2013	Nov	2,182	2,196	10	11	2,531	2,564	16	16
2013	Dec	2,243	2,315	10	10	3,774	3,889	21	22
2013	Annual	2,273	2,359	12	13	3,273	3,309	19	19

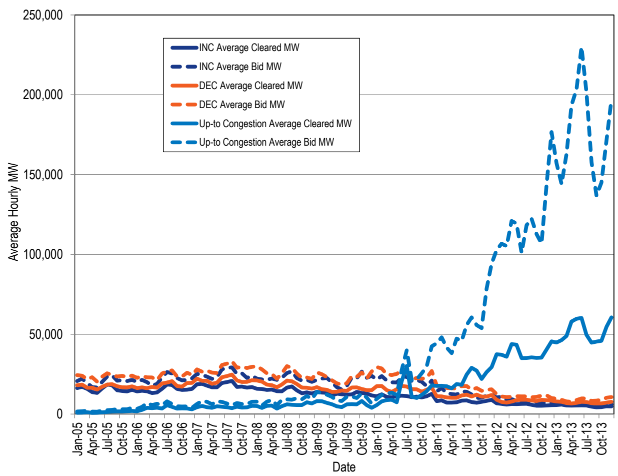
Table 3-34 shows the frequency with which generation offers, import or export transactions, up-to congestion transactions, decrement bids, increment offers and price-sensitive demand are marginal for each month.

Table 3-34 Type of day-ahead marginal units: 2013

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	3.8%	0.1%	91.7%	2.6%	1.8%	0.0%
Feb	3.4%	0.1%	92.9%	1.8%	1.8%	0.0%
Mar	2.5%	0.1%	95.8%	0.8%	0.8%	0.0%
Apr	0.4%	0.0%	98.5%	0.4%	0.6%	0.0%
May	0.6%	0.1%	98.4%	0.5%	0.4%	0.0%
Jun	0.6%	0.0%	97.5%	1.3%	0.7%	0.0%
Jul	0.8%	0.1%	97.0%	1.4%	0.7%	0.0%
Aug	0.4%	0.0%	97.6%	0.9%	1.1%	0.0%
Sep	0.6%	0.0%	96.2%	1.5%	1.6%	0.0%
Oct	0.5%	0.0%	96.9%	1.6%	1.0%	0.0%
Nov	0.4%	0.0%	96.9%	0.9%	1.8%	0.0%
Dec	0.3%	0.0%	97.2%	1.6%	0.8%	0.0%
Annual	1.2%	0.0%	96.4%	1.3%	1.1%	0.0%

Figure 3-22 shows the hourly volume of bid and cleared INC, DEC and up-to congestion bids by month.

Figure 3-22 Hourly number of bid and cleared INC, DEC and Up-to Congestion bids (MW) by month: January, 2005 through December, 2013



In order to evaluate the ownership of virtual bids, the MMU categorizes 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 3-35 shows, for 2012 and 2013, the total increment offers and decrement bids by whether the parent organization is financial or physical. Table 3-36 shows, for 2012 and 2013, the total up-to congestion transactions by the type of parent organization. Table 3-37 shows, for 2012 and 2013, the total import and export transactions by whether the parent organization is financial or physical.

The top five companies with cleared up-to congestion transactions are financial and account for 57.4 percent of all the cleared up-to congestion MW in PJM in 2013.

Table 3-35 PJM INC and DEC bids by type of parent organization (MW): 2012 and 2013

	2012		2013	
Category	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	59,843,681	34.9%	38,937,242	28.6%
Physical	111,507,235	65.1%	97,174,588	71.4%
Total	171,350,915	100.0%	136,111,830	100.0%

Table 3-36 PJM up-to congestion transactions by type of parent organization (MW): 2012 and 2013

	2012		2013	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	318,217,668	94.7%	432,126,914	95.6%
Physical	17,660,315	5.3%	19,875,032	4.4%
Total	335,877,984	100.0%	452,001,946	100.0%

Table 3-37 PJM import and export transactions by type of parent organization (MW): 2012 and 2013

	2012		2013	
Category	Total Import and Export MW	Percentage	Total Import and Export MW	Percentage
Financial	18,967,523	37.5%	20,687,175	42.6%
Physical	31,625,338	62.5%	27,894,650	57.4%
Total	50,592,861	100.0%	48,581,824	100.0%

Table 3-38 shows increment offers and decrement bids bid by top ten locations for 2012 and 2013.

Table 3-38 PJM virtual offers and bids by top ten locations (MW): 2012 and 2013

2012					2013				
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	30,251,322	34,038,502	64,289,824	WESTERN HUB	HUB	23,704,798	26,371,972	50,076,770
AEP-DAYTON HUB	HUB	5,095,250	6,203,179	11,298,428	N ILLINOIS HUB	HUB	2,505,103	5,215,686	7,720,789
N ILLINOIS HUB	HUB	2,523,882	6,051,839	8,575,721	AEP-DAYTON HUB	HUB	3,518,334	3,519,477	7,037,811
SOUTHIMP	INTERFACE	8,243,907	0	8,243,907	SOUTHIMP	INTERFACE	6,789,355	0	6,789,355
MISO	INTERFACE	311,129	7,046,379	7,357,509	IMO	INTERFACE	6,024,071	50,665	6,074,736
PPL	ZONE	327,795	5,785,740	6,113,535	PPL	ZONE	93,834	5,350,860	5,444,694
PECO	ZONE	889,065	4,026,280	4,915,345	MISO	INTERFACE	372,546	3,911,548	4,284,094
IMO	INTERFACE	3,665,471	73,627	3,739,098	PECO	ZONE	118,146	3,844,769	3,962,915
BGE	ZONE	173,888	2,161,310	2,335,198	BGE	ZONE	34,983	2,187,127	2,222,109
METED	ZONE	153,851	1,421,991	1,575,842	DOMINION HUB	HUB	346,732	1,582,833	1,929,564
Top ten total		51,635,560	66,808,846	118,444,406			43,507,901	52,034,937	95,542,838
PJM total		73,945,975	97,404,941	171,350,915			56,506,245	79,605,585	136,111,830
Top ten total as percent of PJM total		69.8%	68.6%	69.1%			77.0%	65.4%	70.2%

Table 3-39 shows up-to congestion transactions by import bids for the top ten locations for 2012 and 2013.[55]

Table 3-39 PJM cleared up-to congestion import bids by top ten source and sink pairs (MW): 2012 and 2013

2012 Imports				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	112 WILTON	EHVAGG	9,190,395
OVEC	INTERFACE	DEOK	ZONE	2,413,946
MISO	INTERFACE	N ILLINOIS HUB	HUB	2,381,726
OVEC	INTERFACE	JEFFERSON	EHVAGG	2,143,300
NYIS	INTERFACE	HUDSON BC	AGGREGATE	2,111,405
OVEC	INTERFACE	MARYSVILLE	EHVAGG	1,864,666
MISO	INTERFACE	COOK	EHVAGG	1,841,613
OVEC	INTERFACE	COOK	EHVAGG	1,785,331
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	1,784,828
OVEC	INTERFACE	BIG SANDY CT1	AGGREGATE	1,686,217
Top ten total				27,203,428
PJM total				146,428,449
Top ten total as percent of PJM total				18.6%
2013 Imports				
Source	Source Type	Sink	Sink Type	MW
OVEC	INTERFACE	DEOK	ZONE	1,277,685
OVEC	INTERFACE	STUART 1	AGGREGATE	1,033,271
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	971,443
NYIS	INTERFACE	HUDSON BC	AGGREGATE	894,530
NORTHWEST	INTERFACE	ZION 1	AGGREGATE	733,906
NORTHWEST	INTERFACE	BYRON 1	AGGREGATE	576,253
OVEC	INTERFACE	BECKJORD 6	AGGREGATE	569,729
OVEC	INTERFACE	SPORN 2	AGGREGATE	524,883
IMO	INTERFACE	WESTERN HUB	HUB	489,032
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	482,986
Top ten total				7,553,718
PJM total				40,902,161
Top ten total as percent of PJM total				18.5%

Table 3-40 shows up-to congestion transactions by export bids for the top ten locations for 2012 and 2013.

Table 3-40 PJM cleared up-to congestion export bids by top ten source and sink pairs (MW): 2012 and 2013

2012 Exports				
Source	Source Type	Sink	Sink Type	MW
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	3,715,287
ROCKPORT	EHVAGG	OVEC	INTERFACE	3,343,889
23 COLLINS	EHVAGG	MISO	INTERFACE	3,085,476
STUART 1	AGGREGATE	OVEC	INTERFACE	2,386,394
GAVIN	EHVAGG	OVEC	INTERFACE	1,932,567
ROCKPORT	EHVAGG	MISO	INTERFACE	1,854,904
QUAD CITIES 1	AGGREGATE	NORTHWEST	INTERFACE	1,841,009
SPORN 5	AGGREGATE	OVEC	INTERFACE	1,803,365
SPORN 3	AGGREGATE	OVEC	INTERFACE	1,792,405
WESTERN HUB	HUB	MISO	INTERFACE	1,661,684
Top ten total				23,416,981
PJM total				150,988,394
Top ten total as percent of PJM total				15.5%
2013 Exports				
Source	Source Type	Sink	Sink Type	MW
JEFFERSON	EHVAGG	OVEC	INTERFACE	2,337,713
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	1,489,113
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	1,347,573
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	1,233,366
TANNERS CRK 4	AGGREGATE	OVEC	INTERFACE	1,157,724
ROCKPORT	EHVAGG	OVEC	INTERFACE	1,007,610
F387 CHICAGOH	AGGREGATE	NIPSCO	INTERFACE	828,452
GAVIN	EHVAGG	OVEC	INTERFACE	706,465
21 KINCA ATR24304	AGGREGATE	OVEC	INTERFACE	688,745
EAST BEND 2	AGGREGATE	OVEC	INTERFACE	661,555
Top Ten Total				11,458,315
PJM total				49,738,703
Top ten total as percent of PJM total				23.0%

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 3-41 shows up-to congestion transactions by wheel bids for the top ten locations for 2012 and 2013.

Table 3-41 PJM cleared up-to congestion wheel bids by top ten source and sink pairs (MW): 2012 and 2013

2012				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	540,158
MISO	INTERFACE	NIPSCO	INTERFACE	198,665
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	192,006
NYIS	INTERFACE	IMO	INTERFACE	167,433
SOUTHIMP	INTERFACE	MISO	INTERFACE	149,798
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	149,407
MISO	INTERFACE	OVEC	INTERFACE	147,574
IMO	INTERFACE	NYIS	INTERFACE	138,041
NORTHWEST	INTERFACE	MISO	INTERFACE	131,420
OVEC	INTERFACE	IMO	INTERFACE	118,486
Top ten total				1,932,987
PJM total				2,974,891
Top ten total as percent of PJM total				65.0%
2013				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	766,264
NORTHWEST	INTERFACE	MISO	INTERFACE	677,453
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	479,746
IMO	INTERFACE	NYIS	INTERFACE	330,340
MISO	INTERFACE	NIPSCO	INTERFACE	303,181
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	143,047
OVEC	INTERFACE	IMO	INTERFACE	131,155
MISO	INTERFACE	SOUTHEXP	INTERFACE	118,693
LINDENVFT	INTERFACE	NYIS	INTERFACE	86,796
MISO	INTERFACE	OVEC	INTERFACE	83,065
Top ten total				3,119,740
PJM total				4,177,320
Top ten total as percent of PJM total				74.7%

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 8.1 percent of the PJM total internal up-to congestion transactions in 2013.

Table 3-42 shows up-to congestion transactions by internal bids for the top ten locations for November through December of 2012, and 2013.

Table 3-42 PJM cleared up-to congestion internal bids by top ten source and sink pairs (MW): November through December of 2012, and 2013

2012 (Nov - Dec)				
Internal				
Source	Source Type	Sink	Sink Type	MW
NAPERVILLE	AGGREGATE	ZION 1	AGGREGATE	213,928
MARQUIS	EHVAGG	STUART DIESEL	AGGREGATE	205,066
JOLIET 8	AGGREGATE	JOLIET 7	AGGREGATE	189,609
WESTERN HUB	HUB	BGE	ZONE	174,710
SULLIVAN-AEP	EHVAGG	AK STEEL	AGGREGATE	166,152
RENO 138 KV T1	AGGREGATE	OAKGROVE 1	AGGREGATE	160,935
TANNERS CRK 4	AGGREGATE	SPORN 3	AGGREGATE	159,006
ROCKPORT	EHVAGG	JEFFERSON	EHVAGG	156,568
CONEMAUGH	EHVAGG	HUNTERSTOWN	EHVAGG	153,698
N ILLINOIS HUB	HUB	AEP-DAYTON HUB	HUB	152,976
Top ten total				1,732,647
PJM total				35,486,249
Top ten total as percent of PJM total				4.9%
2013				
Internal				
Source	Source Type	Sink	Sink Type	MW
ATSI GEN HUB	HUB	ATSI	ZONE	5,675,792
SUNBURY 1-3	AGGREGATE	CITIZENS	AGGREGATE	4,405,866
MT STORM	EHVAGG	GREENLAND GAP	EHVAGG	3,910,366
FE GEN	AGGREGATE	ATSI	ZONE	2,980,966
WYOMING	EHVAGG	BROADFORD	EHVAGG	2,939,931
AEP-DAYTON HUB	HUB	WESTERN HUB	HUB	2,142,829
SUNBURY 1-3	AGGREGATE	FOSTER WHEELER	AGGREGATE	1,917,015
WHITPAIN	EHVAGG	ELROY	EHVAGG	1,868,461
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	1,559,654
CORDOVA	AGGREGATE	QUAD CITIES 2	AGGREGATE	1,522,733
Top ten total				28,923,614
PJM total				357,183,762
Top ten total as percent of PJM total				8.1%

Table 3-43 shows the number of source-sink pairs that were offered and cleared monthly in 2012 and 2013. The annual row in Table 3-43 is the average hourly number of offered and cleared source-sink pairs for the year for the average columns and the maximum hourly number of offered and cleared source-sink pairs for the year for the maximum columns. The increase in average offered and cleared source-sink pairs beginning in November and December of 2012 and 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.

56 For more information, see the *2013 State of the Market Report for PJM*, Volume II, Section 9, "Interchange Transactions," Up-to Congestion.

Table 3-43 Number of PJM offered and cleared source and sink pairs: 2012 and 2013[57]

		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	2,827	13,009	1,800	8,071
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	Apr	6,426	9,064	3,464	4,827
2013	May	5,729	7,914	3,350	4,495
2013	Jun	6,014	8,437	3,490	4,775
2013	Jul	5,955	9,006	3,242	4,938
2013	Aug	6,215	9,751	3,642	5,117
2013	Sep	3,496	4,222	2,510	3,082
2013	Oct	4,743	7,134	3,235	4,721
2013	Nov	8,605	14,065	5,419	8,069
2013	Dec	8,346	11,728	6,107	7,415
2013	Annual	5,996	14,065	3,620	8,069

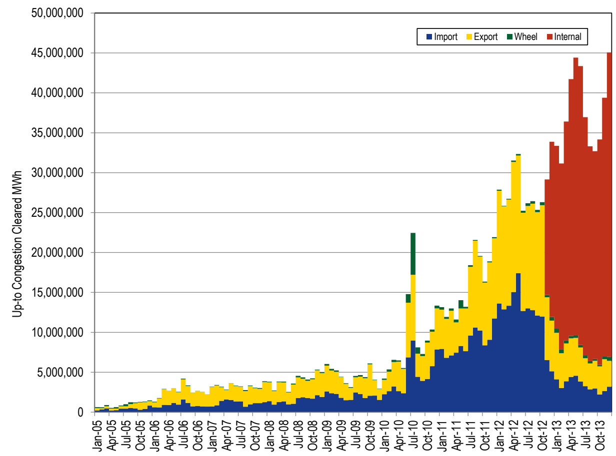
Table 3-44 and Figure 3-23 show total cleared up-to congestion transactions by type for 2012 and 2013. Internal up-to congestion transactions in 2013 were 79.0 percent of all up-to congestion transactions for 2013. In 2013, nine internal up-to congestion transactions were in the top ten total in MW.

Table 3-44 PJM cleared up-to congestion transactions by type (MW): 2012 and 2013

	2012				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	27,203,428	23,416,981	1,932,987	1,732,647	32,704,386
PJM total (MW)	146,428,449	150,988,394	2,974,891	35,486,249	335,877,984
Top ten total as percent of PJM total	18.6%	15.5%	65.0%	4.9%	9.7%
PJM total as percent of all up-to congestion transactions	43.6%	45.0%	0.9%	10.6%	100.0%
	2013				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	7,553,718	628,674	3,119,740	28,923,614	29,738,595
PJM total (MW)	40,902,161	49,738,703	4,177,320	357,183,762	452,001,946
Top ten total as percent of PJM total	18.5%	1.3%	74.7%	8.1%	6.6%
PJM total as percent of all up-to congestion transactions	9.0%	11.0%	0.9%	79.0%	100.0%

Figure 3-23 shows the initial increase and continued rise of internal up-to congestion transactions in November and December of 2012 and 2013, following the November 1, 2012, rule change permitting such transactions.

Figure 3-23 PJM cleared up-to congestion transactions by type (MW): January 2005 through December of 2013



57 The max offered data in the April 2013 row and Annual rows in the corresponding table in the *2013 State of the Market Report for PJM: January through September* were averages and not maximums.

Market Performance

The PJM average locational marginal price (LMP) reflects the configuration of the entire RTO. The PJM Energy Market includes the Real-Time Energy Market and the Day-Ahead Energy Market.

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.[58]

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 the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units.

Table 3-45 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 3-45 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 3-26.

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 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 exclude the 10 percent adder from their actual offers. The unadjusted markup is calculated as the difference between the price

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

offer and the cost offer including the 10 percent adder in the cost offer. 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. Even the adjusted markup underestimates the markup because coal units facing increased competitive pressure have excluded both the ten percent adder and components of operating and maintenance cost. While both these elements are permitted under the definition of cost-based offers in the relevant PJM manual, they are not part of a competitive offer for a coal unit because they are not actually marginal costs and market behavior reflected that fact.[59]

Table 3-45 shows the mark-up component of the load weighted LMP by primary fuel and unit-type using unadjusted and adjusted offers. The adjusted markup component of LMP increased from $0.44 in 2012 to $0.77 in 2013. The markup component of coal units in 2013 was - $0.49. After removing 10 percent adder from the cost offers of coal units, the markup contribution of coal units in 2013 was $1.03. The adjusted mark-up component of all gas-fired units in 2013 was $0.22. The markup component of wind units is zero but this includes a range from negative to positive. If a price-based offer is negative but less negative than a cost-based offer, the markup is positive. In 2013, among the wind units that were marginal, 1.5 percent of units had positive offer prices.

Table 3-45 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: 2012 and 2013[60]

		2012		2013	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($1.69)	$0.11	($0.49)	$1.03
Demand Response	Demand Response	$0.00	$0.00	$0.00	$0.00
Gas	CC	$0.42	$0.42	$0.04	$0.04
Gas	CT	($0.03)	($0.03)	$0.15	$0.15
Gas	Diesel	$0.02	$0.02	$0.03	$0.03
Gas	Steam	($0.03)	($0.03)	$0.00	$0.00
Municipal Waste	Diesel	$0.00	$0.00	$0.00	$0.00
Municipal Waste	Steam	$0.02	$0.02	($0.01)	($0.01)
Oil	CT	$0.01	$0.01	$0.00	$0.00
Oil	Diesel	$0.00	$0.00	$0.00	$0.00
Oil	Steam	($0.08)	($0.08)	($0.46)	($0.46)
Other	Solar	$0.00	$0.00	$0.00	$0.00
Other	Steam	($0.00)	($0.00)	($0.02)	($0.02)
Uranium	Steam	$0.00	$0.00	($0.00)	($0.00)
Wind		($0.00)	($0.00)	$0.00	$0.00
Total		($1.37)	$0.44	($0.76)	$0.77

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, markup is the difference between the active offer of the marginal unit and the cost offer. In the second approach, the 10 percent markup is removed from the cost offers of coal units because coal units do not face the same cost uncertainty as gas-fired CTs. The adjusted markup is calculated as the difference between the active offer and the cost offer excluding the 10 percent adder. The unadjusted markup is calculated as the difference between the active offer and the cost offer including the 10 percent adder in the cost offer.

59 See *PJM Manual 15: Cost Development Guidelines*, Revision: 23 (Effective August 1, 2013).

Markup Component of Real-Time Price

Table 3-46 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on-peak and off-peak prices. Table 3-47 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on-peak and off-peak prices. In 2013, when using unadjusted cost offers, -$0.76 per MWh of the PJM real-time load weighted average LMP was attributable to markup. Using adjusted cost offers, $0.77 per MWh of the PJM real-time load weighted average LMP was attributable

60 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.

to markup. In 2013, the real time load-weighted average LMP for the month of July had the highest markup component, $3.01 per MWh using unadjusted cost offers and $4.37 per MWh using adjusted cost offers. This corresponds to 5.9 percent and 8.6 percent of the July month's real time load-weighted average LMP. The July results demonstrate that markups can increase significantly during high demand periods.

The smallest zonal on peak average markup was in the PPL Control Zone, -$0.41 per MWh, while the highest zonal on peak average markup was in the RECO Control Zone, $1.12 per MWh.

Table 3-46 Monthly markup components of real-time load-weighted LMP (Unadjusted): 2012 and 2013

	2012			2013		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($3.28)	($3.58)	($2.98)	($3.12)	($3.86)	($2.43)
Feb	($2.07)	($2.92)	($1.26)	($1.98)	($3.16)	($0.83)
Mar	($2.30)	($2.51)	($2.10)	$0.26	($1.05)	$1.62
Apr	($2.71)	($3.60)	($1.86)	($1.71)	($2.79)	($0.80)
May	($1.10)	($3.34)	$0.93	($0.46)	($2.25)	$1.04
Jun	($2.67)	($3.24)	($2.17)	($0.62)	($1.09)	($0.15)
Jul	$3.38	($2.36)	$8.82	$3.01	($1.43)	$6.93
Aug	($0.90)	($2.30)	$0.20	($1.69)	($1.88)	($1.53)
Sep	($0.70)	($1.89)	$0.60	($0.94)	($2.35)	$0.46
Oct	($1.16)	($3.00)	$0.37	($0.49)	($1.03)	($0.03)
Nov	($1.25)	($2.40)	($0.13)	($1.14)	($1.60)	($0.64)
Dec	($2.93)	($3.16)	($2.67)	($0.76)	($1.76)	$0.29
Total	($1.37)	($2.85)	$0.03	($0.76)	($2.01)	$0.42

Table 3-47 Monthly markup components of real-time load-weighted LMP (Adjusted): 2012 and 2013

	2012			2013		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($0.93)	($1.40)	($0.43)	($1.28)	($1.88)	($0.72)
Feb	($0.06)	($1.04)	$0.87	($0.19)	($1.24)	$0.83
Mar	($0.59)	($1.07)	($0.15)	$1.93	$0.73	$3.19
Apr	($0.81)	($1.79)	$0.11	($0.43)	($1.13)	$0.16
May	$0.64	($1.71)	$2.78	$0.89	($0.58)	$2.12
Jun	($1.14)	($1.92)	($0.45)	$0.81	$0.35	$1.27
Jul	$5.08	($0.47)	$10.34	$4.37	$0.09	$8.14
Aug	$1.07	($0.60)	$2.38	($0.27)	($0.35)	($0.20)
Sep	$1.01	($0.29)	$2.45	$0.56	($0.58)	$1.68
Oct	$0.30	($1.45)	$1.75	$0.94	$0.61	$1.22
Nov	$0.51	($0.45)	$1.45	$0.44	$0.07	$0.84
Dec	($1.16)	($1.41)	($0.87)	$0.83	($0.05)	$1.76
Total	$0.44	($1.11)	$1.90	$0.77	($0.32)	$1.79

Markup Component of Real-Time Zonal Prices

The average real-time price component of unit markup using unadjusted offers is shown for each zone for 2013 and 2012 in Table 3-48 and for adjusted offers in Table 3-49. The smallest zonal all hours average markup component using unadjusted offers for the 2013 was in the PPL Control Zone, -$1.16 per MWh, while the highest all hours average zonal markup component for 2013 was in the RECO Control Zone, -$0.06 per MWh.

Table 3-48 Average real-time zonal markup component (Unadjusted): 2012 and 2013

	2012			2013		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	($1.17)	($2.64)	$0.26	($0.86)	($1.84)	$0.08
AEP	($1.65)	($2.94)	($0.39)	($0.95)	($2.06)	$0.11
APS	($1.49)	($2.91)	($0.11)	($0.98)	($2.09)	$0.08
ATSI	($1.61)	($3.06)	($0.25)	($0.93)	($2.05)	$0.12
BGE	($1.03)	($2.42)	$0.31	($0.75)	($2.14)	$0.58
ComEd	($1.36)	($3.00)	$0.16	($0.90)	($2.03)	$0.13
DAY	($1.69)	($3.07)	($0.41)	($1.01)	($2.06)	($0.04)
DEOK	($1.66)	($2.97)	($0.42)	($0.98)	($2.03)	$0.01
DLCO	($1.43)	($2.93)	($0.02)	($1.08)	($2.03)	($0.18)
DPL	($1.50)	($3.10)	$0.05	($1.07)	($1.92)	($0.25)
Dominion	($1.01)	($2.49)	$0.42	($0.71)	($1.99)	$0.54
EKPC	NA	NA	NA	($0.61)	($1.68)	$0.47
JCPL	($0.99)	($2.89)	$0.73	($1.11)	($1.99)	($0.32)
Met-Ed	($1.42)	($2.97)	$0.02	($0.91)	($1.99)	$0.08
PECO	($1.28)	($2.74)	$0.10	($1.02)	($1.84)	($0.25)
PENELEC	($1.58)	($3.07)	($0.18)	($1.10)	($2.12)	($0.15)
PPL	($1.51)	($2.99)	($0.12)	($1.16)	($1.96)	($0.41)
PSEG	($1.13)	($2.73)	$0.35	($0.59)	($1.73)	$0.46
Pepco	($0.89)	($2.47)	$0.58	($0.73)	($2.21)	$0.65
RECO	($1.00)	($2.85)	$0.60	($0.06)	($1.45)	$1.12

Table 3-49 Average real-time zonal markup component (Adjusted): 2012 and 2013

	2012			2013		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$0.54	($1.03)	$2.06	$0.64	($0.17)	$1.42
AEP	$0.16	($1.19)	$1.48	$0.61	($0.33)	$1.51
APS	$0.38	($1.16)	$1.87	$0.57	($0.37)	$1.47
ATSI	$0.19	($1.34)	$1.63	$0.66	($0.31)	$1.57
BGE	$1.01	($0.45)	$2.40	$0.77	($0.39)	$1.87
ComEd	$0.43	($1.28)	$2.00	$0.61	($0.41)	$1.53
DAY	$0.16	($1.30)	$1.52	$0.60	($0.31)	$1.43
DEOK	$0.12	($1.26)	$1.43	$0.57	($0.34)	$1.42
DLCO	$0.28	($1.29)	$1.78	$0.46	($0.35)	$1.22
DPL	$0.28	($1.40)	$1.92	$0.44	($0.26)	$1.11
Dominion	$0.86	($0.67)	$2.33	$0.81	($0.26)	$1.85
EKPC	NA	NA	NA	$0.91	($0.02)	$1.84
JCPL	$0.74	($1.21)	$2.51	$0.33	($0.33)	$0.93
Met-Ed	$0.27	($1.36)	$1.79	$0.56	($0.36)	$1.41
PECO	$0.42	($1.09)	$1.85	$0.46	($0.22)	$1.10
PENELEC	$0.19	($1.36)	$1.65	$0.47	($0.40)	$1.27
PPL	$0.19	($1.37)	$1.65	$0.35	($0.31)	$0.96
PSEG	$0.64	($1.07)	$2.22	$0.88	($0.10)	$1.78
Pepco	$1.03	($0.59)	$2.54	$0.74	($0.51)	$1.90
RECO	$0.81	($1.11)	$2.47	$1.41	$0.24	$2.42

Markup by Real Time Price Levels

Table 3-50 show the average markup component of observed prices, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM average LMP was in the identified price range.

Table 3-50 Average real-time markup component (By price category, unadjusted): 2012 and 2013

	2012		2013	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.80)	24.8%	($0.73)	92.1%
$25 to $50	($1.89)	67.7%	($0.11)	7.1%
$50 to $75	$0.35	4.6%	$0.04	0.7%
$75 to $100	$0.25	1.4%	$0.01	0.1%
$100 to $125	$0.10	0.7%	$0.00	0.0%
$125 to $150	$0.11	0.2%	$0.01	0.0%
>= $150	$0.45	0.5%	$0.00	0.0%

Table 3-51 Average real-time markup component (By price category, adjusted): 2012 and 2013

	2012		2013	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.53)	24.8%	$0.70	92.1%
$25 to $50	($0.44)	67.7%	$0.03	7.1%
$50 to $75	$0.44	4.6%	$0.04	0.7%
$75 to $100	$0.28	1.4%	$0.01	0.1%
$100 to $125	$0.12	0.7%	$0.00	0.0%
$125 to $150	$0.12	0.2%	$0.01	0.0%
>= $150	$0.46	0.5%	$0.00	0.0%

Day-Ahead Markup

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

Table 3-52 Markup component of the annual PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: 2012 and 2013

		2012		2013	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($1.72)	($0.72)	($0.41)	($0.15)
Gas	Steam	($0.13)	($0.13)	($0.36)	($0.36)
Oil	Steam	($0.06)	($0.06)	($0.00)	($0.00)
Municipal Waste	Steam	($0.00)	($0.00)	($0.00)	($0.00)
Wind	Wind	($0.00)	($0.00)	$0.00	$0.00
Gas	CT	$0.06	$0.06	($0.02)	($0.02)
Total		($1.86)	($0.85)	($0.78)	($0.53)

The markup component of the PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 3-52. INC, DEC and up-to congestion transactions have zero markups. Up-to congestion transactions were marginal for 96.4 percent of marginal resources in 2013. INCs were marginal for 1.3 percent of marginal resources and DECs were marginal for 1.1 percent of marginal resources in 2013. The adjusted markup of coal units is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder. Table 3-52 shows the markup component of LMP for marginal generating resources. Generating resources were marginal in only 1.2 percent of marginal resources in 2013.

Markup Component of Day-Ahead Price

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units. Only hours when generating units were marginal on either priced based offers or on cost based offers were included in the markup calculation.

Table 3-53 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted offers. Table 3-54 shows the markup component of average prices and of average monthly on-peak and off-peak prices using adjusted offers.

Table 3-53 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: 2012 and 2013

	2012			2013		
	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)
Apr	($2.67)	($2.36)	($2.98)	($0.11)	($0.01)	($0.22)
May	($1.52)	($1.11)	($1.97)	($0.10)	($0.04)	($0.17)
Jun	($1.93)	($1.09)	($2.88)	($0.06)	$0.03	($0.14)
Jul	$0.35	$2.60	($2.07)	($0.08)	($0.01)	($0.15)
Aug	($1.86)	($0.95)	($3.05)	($0.06)	($0.01)	($0.11)
Sep	($1.75)	($1.36)	($2.10)	($0.27)	($0.13)	($0.42)
Oct	($0.95)	($0.06)	($2.03)	($0.06)	($0.06)	($0.06)
Nov	($2.05)	($0.86)	($3.29)	($0.32)	($0.10)	($0.52)
Dec	($2.42)	($1.97)	($2.82)	$0.01	$0.00	$0.02
Annual	($1.86)	($1.14)	($2.63)	($0.78)	($0.51)	($1.07)

Table 3-54 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: 2012 and 2013

	2012			2013		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($1.43)	($1.00)	($1.84)	($2.66)	($3.01)	($2.28)
Feb	($1.74)	($2.21)	($1.25)	($1.67)	($0.67)	($2.70)
Mar	($1.37)	($1.05)	($1.72)	($1.29)	$0.07	($2.61)
Apr	($1.49)	($1.18)	($1.81)	($0.03)	$0.04	($0.11)
May	($0.76)	($0.33)	($1.23)	($0.04)	($0.02)	($0.06)
Jun	($0.92)	($0.04)	($1.91)	($0.02)	$0.04	($0.07)
Jul	$1.24	$3.35	($1.03)	($0.03)	$0.02	($0.09)
Aug	($0.93)	($0.11)	($2.01)	($0.02)	$0.01	($0.05)
Sep	($0.82)	($0.44)	($1.17)	($0.17)	($0.08)	($0.26)
Oct	($0.14)	$0.56	($1.00)	($0.04)	($0.02)	($0.07)
Nov	($1.09)	($0.40)	($1.82)	($0.23)	($0.07)	($0.39)
Dec	($1.34)	($0.93)	($1.69)	$0.04	$0.00	$0.07
Annual	($0.85)	($0.21)	($1.54)	($0.53)	($0.32)	($0.74)

Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted offers is shown for each zone in Table 3-55. The markup component of annual average day-ahead price using adjusted offers is shown for each zone in Table 3-56.

Table 3-55 Day-ahead, average, zonal markup component (Unadjusted): 2012 and 2013

	2012			2013		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($1.56)	($0.66)	($2.53)	($0.80)	($0.56)	($1.06)
AEP	($1.94)	($1.26)	($2.65)	($0.80)	($0.49)	($1.12)
AP	($1.87)	($1.30)	($2.47)	($0.86)	($0.55)	($1.19)
ATSI	($1.99)	($1.32)	($2.72)	($0.80)	($0.49)	($1.13)
BGE	($1.86)	($1.19)	($2.57)	($0.80)	($0.55)	($1.06)
ComEd	($1.77)	($1.17)	($2.44)	($0.72)	($0.44)	($1.02)
DAY	($1.90)	($1.19)	($2.68)	($0.81)	($0.49)	($1.16)
DEOK	($1.85)	($1.17)	($2.56)	($0.76)	($0.44)	($1.11)
DLCO	($1.83)	($1.13)	($2.59)	($0.76)	($0.47)	($1.07)
DPL	($1.67)	($0.85)	($2.55)	($0.84)	($0.52)	($1.18)
Dominion	($1.79)	($1.03)	($2.57)	($0.78)	($0.53)	($1.06)
EKPC	NA	NA	NA	($0.12)	($0.03)	($0.22)
JCPL	($1.54)	($0.66)	($2.53)	($0.95)	($0.82)	($1.08)
Met-Ed	($1.85)	($1.13)	($2.65)	($0.86)	($0.61)	($1.14)
PECO	($1.71)	($0.98)	($2.49)	($0.80)	($0.52)	($1.11)
PENELEC	($2.07)	($1.50)	($2.69)	($0.72)	($0.52)	($0.93)
PPL	($2.04)	($1.43)	($2.71)	($0.89)	($0.64)	($1.16)
PSEG	($1.59)	($0.61)	($2.69)	($0.77)	($0.51)	($1.07)
Pepco	($1.86)	($1.25)	($2.52)	($0.80)	($0.56)	($1.06)
RECO	($1.49)	($0.54)	($2.63)	($0.75)	($0.46)	($1.08)

Table 3-56 Day-ahead, average, zonal markup component (Adjusted): 2012 and 2013

	2012			2013		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.60)	$0.23	($1.48)	($0.55)	($0.37)	($0.74)
AEP	($0.91)	($0.30)	($1.55)	($0.52)	($0.29)	($0.77)
AP	($0.83)	($0.33)	($1.36)	($0.57)	($0.35)	($0.81)
ATSI	($0.93)	($0.32)	($1.60)	($0.52)	($0.29)	($0.77)
BGE	($0.79)	($0.20)	($1.42)	($0.56)	($0.39)	($0.73)
ComEd	($0.82)	($0.27)	($1.43)	($0.48)	($0.26)	($0.73)
DAY	($0.85)	($0.20)	($1.56)	($0.53)	($0.29)	($0.80)
DEOK	($0.84)	($0.22)	($1.50)	($0.50)	($0.26)	($0.76)
DLCO	($0.86)	($0.21)	($1.56)	($0.50)	($0.28)	($0.73)
DPL	($0.71)	$0.03	($1.49)	($0.57)	($0.34)	($0.82)
Dominion	($0.79)	($0.13)	($1.47)	($0.54)	($0.35)	($0.73)
EKPC	NA	NA	NA	($0.07)	($0.01)	($0.13)
JCPL	($0.57)	$0.23	($1.47)	($0.65)	($0.55)	($0.76)
Met-Ed	($0.90)	($0.26)	($1.60)	($0.60)	($0.42)	($0.80)
PECO	($0.75)	($0.10)	($1.46)	($0.55)	($0.34)	($0.78)
PENELEC	($1.04)	($0.52)	($1.59)	($0.46)	($0.31)	($0.61)
PPL	($1.07)	($0.54)	($1.65)	($0.62)	($0.44)	($0.82)
PSEG	($0.62)	$0.27	($1.63)	($0.52)	($0.33)	($0.74)
Pepco	($0.84)	($0.31)	($1.42)	($0.56)	($0.39)	($0.73)
RECO	($0.52)	$0.35	($1.56)	($0.51)	($0.30)	($0.75)

Markup by Day-Ahead Price Levels

Table 3-57 and Table 3-58 show the average markup component of observed prices, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range.

Table 3-57 Average, day-ahead markup (By LMP category, unadjusted): 2012 and 2013

	2012		2013	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($3.25)	21.0%	($1.25)	5.0%
$25 to $50	($2.69)	74.9%	($2.76)	84.5%
$50 to $75	$2.06	3.0%	$0.69	8.6%
$75 to $100	$6.62	0.6%	$0.03	1.1%
$100 to $125	$18.93	0.2%	$0.01	0.4%
$125 to $150	$4.54	0.1%	$0.00	0.1%
>= $150	$16.80	0.2%	($0.30)	0.4%

Table 3-58 Average, day-ahead markup (By LMP category, adjusted): 2012 and 2013

	2012		2013	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($2.29)	21.0%	($0.70)	5.0%
$25 to $50	($1.33)	74.9%	($1.91)	84.5%
$50 to $75	$2.40	3.0%	$0.76	8.6%
$75 to $100	$6.84	0.6%	$0.09	1.1%
$100 to $125	$19.30	0.2%	($0.03)	0.4%
$125 to $150	$4.91	0.1%	$0.00	0.1%
>= $150	$16.85	0.2%	($0.30)	0.4%

Prices

The conduct of individual market entities within a market structure is reflected in market prices.[61] PJM locational marginal prices (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 9.7 percent and 12.7 percent higher in 2013 than in 2012 as a result of higher fuel costs and higher demand.[62] Natural gas prices were higher, particularly in eastern zones, while coal prices were relatively constant.

PJM real-time energy market prices increased in 2013 compared to 2012. The system average LMP was 10.4 percent higher in 2013 than in 2012, $36.55 per MWh versus $33.11 per MWh. The load-weighted average LMP was 9.7 percent higher in 2013 than in 2012, $38.66 per MWh versus $35.23 per MWh.

The fuel-cost adjusted, load weighted, average LMP for 2013 was 10.9 percent lower than the load weighted, average LMP for 2013. 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, $34.46 per MWh instead of the observed $38.66 per MWh.

PJM day-ahead energy market prices increased in 2013 compared to 2012. The system average LMP was 13.3 percent higher in 2013 than in 2012, $37.15 per MWh versus $32.79 per MWh. The load-weighted average LMP was 12.7 percent higher in 2013 than in 2012, $38.93 per MWh versus $34.55 per MWh.[63]

Real-Time LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[64]

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 3-24 shows the hourly distribution of PJM real-time average LMP for 2012 and 2013. In 2012, there 40 hours in PJM where the real-time LMP for the entire system was negative compared to one hour in 2013. The average negative real-time LMP, for the hours when the LMP was negative, in 2012 was -$18.55 compared to -$0.57 in 2013. Negative LMPs in the PJM Real-Time Market result primarily when wind units with negative offer prices become marginal, but may also result within a constrained area when inflexible generation exceeds the forecasted load. In 2012, there were 12 hours where the PJM real-time LMP was $0.00 compared to two

61 See the *2013 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, at "Calculating Locational Marginal Price" for more information on how bus LMPs are aggregated to system LMPs. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

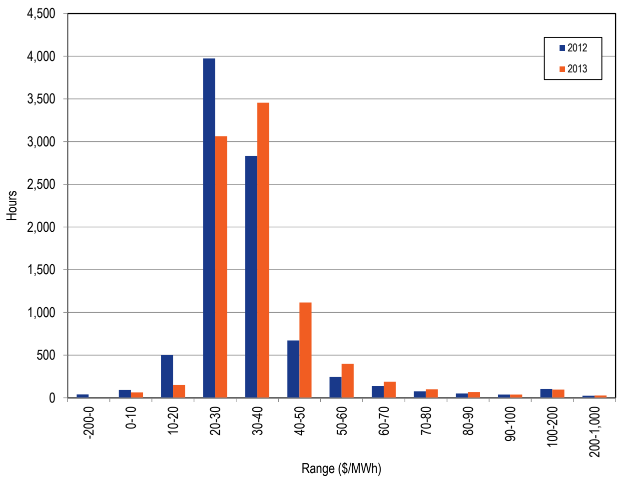
62 There was an average increase of 2.3 heating degree days and an average reduction of 0.7 cooling degree days in 2013 compared to 2012 which meant overall increased demand.

63 Tables reporting zonal and jurisdictional load and prices are in the *2013 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

64 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

hours in 2013. The real-time LMP is $0.00 for hours where a minimum generation event occurs.

Figure 3-24 Average LMP for the PJM Real-Time Energy Market: 2012 and 2013



PJM Real-Time, Average LMP

Table 3-59 shows the PJM real-time, average LMP for each year of the 16-year period 1998 to 2013.[65]

Table 3-59 PJM real-time, average LMP (Dollars per MWh): 1998 through 2013

	Real-Time LMP			Year-to-Year Change		
Year	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.1%)	(41.1%)	(55.7%)
2010	$44.83	$36.88	$26.20	20.9%	12.7%	53.1%
2011	$42.84	$35.38	$29.03	(4.4%)	(4.1%)	10.8%
2012	$33.11	$29.53	$20.67	(22.7%)	(16.5%)	(28.8%)
2013	$36.55	$32.25	$20.57	10.4%	9.2%	(0.5%)

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 3-60 shows the PJM real-time, load-weighted, average LMP for each year of the 16-year period 1998 to 2013.

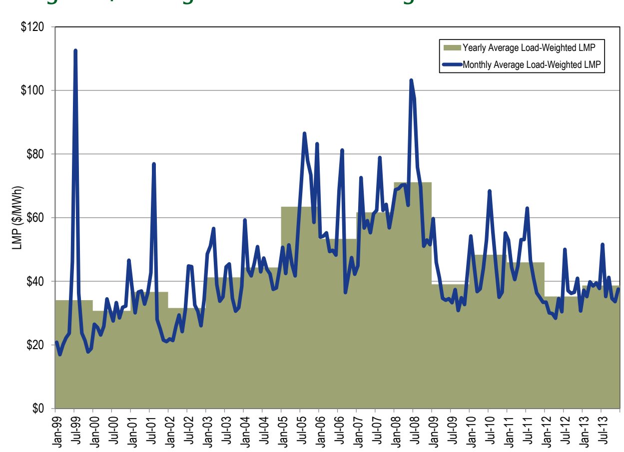
Table 3-60 PJM real-time, load-weighted, average LMP (Dollars per MWh): 1998 through 2013

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
Year	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	23.8%	14.3%	58.7%
2011	$45.94	$36.54	$33.47	(5.0%)	(6.6%)	15.8%
2012	$35.23	$30.43	$23.66	(23.3%)	(16.7%)	(29.3%)
2013	$38.66	$33.25	$23.78	9.7%	9.3%	0.5%

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

Figure 3-25 shows the PJM real-time monthly and annual load-weighted LMP from 1999 through 2013.

Figure 3-25 PJM real-time, monthly and annual, load-weighted, average LMP: 1999 through 2013



65 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.

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 2013. Comparing prices in 2013 to 2012, the price of Northern Appalachian coal was 1.0 percent higher; the price of Central Appalachian coal was 0.3 percent higher; the price of Powder River Basin coal was 20.0 percent higher; the price of eastern natural gas was 40.0 percent higher; and the price of western natural gas was 32.0 percent higher. Figure 3-26 shows monthly average spot fuel prices for 2012 and 2013.[66] Natural gas prices were above coal prices in 2013.

Figure 3-26 Spot average fuel price comparison with fuel delivery charges: 2012 through 2013 ($/MMBtu)

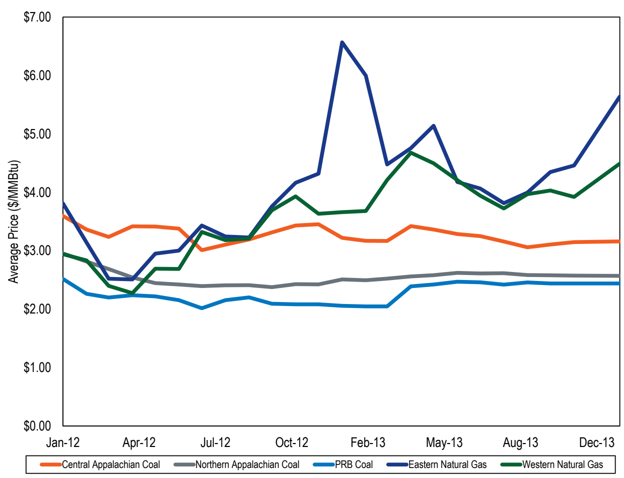


Table 3-61 compares the 2013 PJM real time fuel-cost adjusted, load weighted, average LMP to the 2012 load-weighted, average LMP. The real time fuel-cost adjusted, load weighted, average LMP for 2013 was 10.9 percent lower than the real time load weighted, average LMP for 2013. The real-time, fuel-cost adjusted, load weighted, average LMP for 2013 was 2.2 percent lower than the real time load weighted LMP for 2012. If fuel costs in 2013 had been the same as in 2012, holding everything else constant, the 2013 real time load weighted LMP would have been lower, $34.46 per MWh instead of the observed $38.66 per MWh.

Table 3-61 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	$38.66	$34.46	(10.9%)
	2012 Load-Weighted LMP	2013 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$35.23	$34.46	(2.2%)
	2012 Load-Weighted LMP	2013 Load-Weighted LMP	Change
Average	$35.23	$38.66	9.7%

Table 3-62 shows the impact of each fuel type on the difference between the 2013 fuel-cost adjusted, load-weighted average LMP and the 2013 load weighted LMP. Table 3-62 shows that higher natural gas prices explain almost all of the fuel-cost related increase in the real time annual load-weighted average LMP in 2013.

Table 3-62 Change in PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh) by Fuel-type: Year-over-year method

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Coal	$0.13	3.0%
Gas	$4.19	99.7%
Oil	($0.10)	(2.5%)
Other	($0.00)	(0.0%)
Uranium	($0.00)	(0.0%)
Wind	($0.00)	(0.0%)
Total	$4.20	100.0%

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 forecasts of system conditions. Those offers can be decomposed into components including 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 LMP by the components of unit offers.

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_x, SO_2 and

66 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.

CO_2 emission credits, emission rates for NO_x, emission rates for SO_2 and emission rates for CO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland and New Jersey.[67] 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.

Prior to the implementation of scarcity pricing on October 1, 2012, LMPs calculated based on SCED were modified ex-post (five minutes) 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 now relies entirely on ex-ante pricing. After October 1, 2012, real-time LMPs are based solely on the SCED solution.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes energy and ancillary services. In periods when generators providing energy have to be dispatched down from their economic operating level to meet reserve requirements, the joint optimization of energy and reserves takes into account the opportunity cost of the lowered generation and the associated incremental cost to maintain reserves. If a unit incurring such opportunity costs is a marginal resource in the energy market, this opportunity cost contributes to LMP.

The components of LMP are shown in Table 3-63, including markup using unadjusted cost offers.[68] Table 3-63 shows that for 2013, 46.6 percent of the load-weighted LMP was the result of coal costs, 27.6 percent was the result of gas costs and 0.63 percent was the result of the cost of emission allowances. Markup was -$0.76 per MWh. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP and does not reflect the other components of the offers of units burning that fuel. The component NA is the unexplainable portion of load-weighted LMP. Occasionally, PJM fails to provide all the data needed to accurately calculate generator sensitivity factors. As a result, the LMP for those intervals cannot be decomposed into component costs. The cumulative effect of excluding those five-minute intervals is the component NA. In 2013, nearly eight percent of all five-minute intervals had insufficient data. The percent column is the difference in the proportion of LMP represented by each component between 2013 and 2012.

Table 3-63 Components of PJM real-time (Unadjusted), annual, load-weighted, average LMP: 2013 and 2012

	2012		2013		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$18.90	53.6%	$18.04	46.6%	(7.0%)
Gas	$8.39	23.8%	$10.69	27.6%	3.8%
Ten Percent Adder	$3.48	9.9%	$3.51	9.1%	(0.8%)
VOM	$2.52	7.2%	$2.24	5.8%	(1.4%)
NA	$1.16	3.3%	$1.61	4.2%	0.9%
FMU Adder	$0.10	0.3%	$1.55	4.0%	3.7%
Oil	$1.69	4.8%	$1.28	3.3%	(1.5%)
LPA Rounding Difference	$0.35	1.0%	$0.22	0.6%	(0.4%)
Ancillary Service Redispatch Cost	$0.00	0.0%	$0.17	0.4%	0.4%
Emergency DR Adder	$0.00	0.0%	$0.17	0.4%	0.4%
CO_2 Cost	$0.09	0.3%	$0.13	0.3%	0.1%
NO_x Cost	$0.10	0.3%	$0.10	0.2%	(0.0%)
Increase Generation Adder	$0.12	0.3%	$0.04	0.1%	(0.2%)
SO_2 Cost	$0.02	0.1%	$0.01	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.04)	(0.1%)	$0.00	0.0%	0.1%
Other	$0.01	0.0%	$0.00	0.0%	(0.0%)
Constraint Violation Adder	$0.02	0.1%	$0.00	0.0%	(0.1%)
Market-to-Market Adder	$0.02	0.1%	($0.00)	(0.0%)	(0.1%)
Decrease Generation Adder	($0.22)	(0.6%)	($0.13)	(0.3%)	0.3%
LPA-SCED Differential	($0.10)	(0.3%)	($0.21)	(0.6%)	(0.3%)
Markup	($1.37)	(3.9%)	($0.76)	(2.0%)	1.9%
Total	$35.23	100.0%	$38.66	100.0%	

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 3-63 and Table 3-67) markup is simply the difference between the price offer and the cost offer. In the second approach, (Table 3-64 and Table 3-68) the 10 percent markup is removed from the cost offers of coal units.

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

68 These components are explained in the *Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

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 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 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 adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder from the cost offer. Even the adjusted markup underestimates the markup because coal units facing increased competitive pressure have also excluded components of operating and maintenance cost that, while permitted under the PJM manuals, are not actually marginal costs.[69]

The components of LMP are shown in Table 3-64, including markup using adjusted cost offers.

Table 3-64 Components of PJM real-time (Adjusted), annual, load-weighted, average LMP: 2013 and 2012

	2012		2013		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$19.06	54.1%	$18.35	47.5%	(6.7%)
Gas	$8.39	23.8%	$10.69	27.6%	3.8%
VOM	$2.53	7.2%	$2.27	5.9%	(1.3%)
Ten Percent Adder	$1.50	4.3%	$1.87	4.8%	0.6%
NA	$1.16	3.3%	$1.61	4.2%	0.9%
FMU Adder	$0.10	0.3%	$1.32	3.4%	3.1%
Oil	$1.69	4.8%	$1.28	3.3%	(1.5%)
Markup	$0.44	1.2%	$0.77	2.0%	0.7%
LPA Rounding Difference	$0.35	1.0%	$0.22	0.6%	(0.4%)
Ancillary Service Redispatch Cost	$0.00	0.0%	$0.17	0.4%	0.4%
Emergency Demand Response Adder	$0.00	0.0%	$0.17	0.4%	0.4%
CO_2 Cost	$0.09	0.3%	$0.13	0.3%	0.1%
NO_x Cost	$0.10	0.3%	$0.10	0.3%	(0.0%)
Increase Generation Adder	$0.12	0.3%	$0.04	0.1%	(0.2%)
SO_2 Cost	$0.02	0.1%	$0.01	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.04)	(0.1%)	$0.00	0.0%	0.1%
Other	$0.01	0.0%	$0.00	0.0%	(0.0%)
Constraint Violation Adder	$0.02	0.1%	$0.00	0.0%	(0.1%)
Market-to-Market Adder	$0.02	0.1%	($0.00)	(0.0%)	(0.1%)
Decrease Generation Adder	($0.22)	(0.6%)	($0.13)	(0.3%)	0.3%
LPA-SCED Differential	($0.10)	(0.3%)	($0.21)	(0.6%)	(0.3%)
Total	$35.23	100.0%	$38.66	100.0%	

Day-Ahead LMP

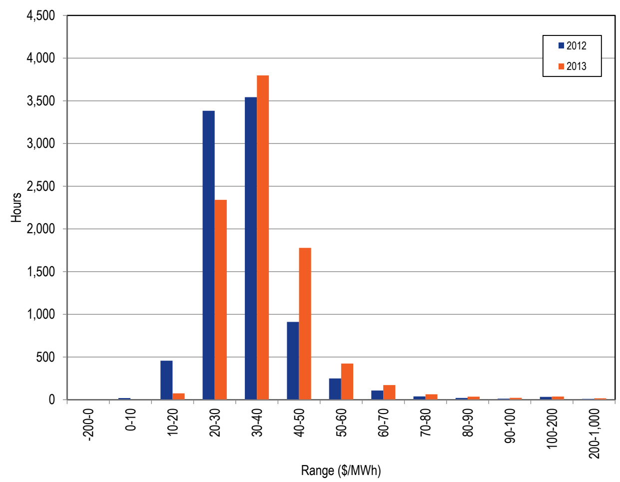
Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[70]

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-27 shows the hourly distribution of PJM day-ahead average LMP for 2012 and 2013.

Figure 3-27 Average LMP for the PJM Day-Ahead Energy Market: 2012 and 2013



69 See *PJM Manual 15: Cost Development Guidelines*, Revision: 23 (Effective August 1, 2013).

70 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for a detailed definition of Day-Ahead LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

PJM Day-Ahead, Average LMP

Table 3-65 shows the PJM day-ahead, average LMP for each year of the 13-year period 2001 to 2013.

Table 3-65 PJM day-ahead, average LMP (Dollars per MWh): 2001 through 2013

	Day-Ahead LMP			Year-to-Year Change		
Year	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$32.75	$27.05	$30.42	NA	NA	NA
2002	$28.46	$23.28	$17.68	(13.1%)	(14.0%)	(41.9%)
2003	$38.73	$35.22	$20.84	36.1%	51.3%	17.8%
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.4%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	(44.0%)	(40.3%)	(56.6%)
2010	$44.57	$39.97	$18.83	20.5%	13.7%	40.6%
2011	$42.52	$38.13	$20.48	(4.6%)	(4.6%)	8.8%
2012	$32.79	$30.89	$13.27	(22.9%)	(19.0%)	(35.2%)
2013	$37.15	$34.63	$15.46	13.3%	12.1%	16.5%

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 3-66 shows the PJM day-ahead, load-weighted, average LMP for each year of the 13-year period 2001 to 2013.

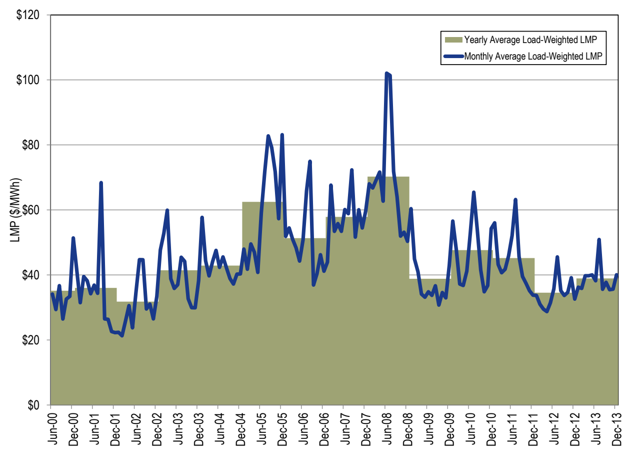
Table 3-66 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): 2001 through 2013

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
Year	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.01	$29.02	$37.48	NA	NA	NA
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	(44.7%)	(41.7%)	(57.7%)
2010	$47.65	$42.06	$20.59	22.7%	14.7%	46.8%
2011	$45.19	$39.66	$24.05	(5.2%)	(5.7%)	16.8%
2012	$34.55	$31.84	$15.48	(23.5%)	(19.7%)	(35.6%)
2013	$38.93	$35.77	$18.05	12.7%	12.3%	16.6%

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

Figure 3-28 shows the PJM day-ahead, monthly annual, load-weighted LMP from 2000 through 2013.[71]

Figure 3-28 Day-ahead, monthly and annual, load-weighted, average LMP: 2000 through 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 their components including 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 with an offer price that cannot be decomposed. Using identified marginal resource offers and the components of unit offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, emission rates for NO_x, emission rates for SO_2 and emission rates for CO_2. CO_2 emission costs are applicable to PJM units in the PJM states that participate

71 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

in RGGI: Delaware, Maryland and New Jersey.[72] 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. 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.

The components of day-ahead LMP are shown in Table 3-67, including markup using unadjusted cost offers. Table 3-67 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In 2013, 71.9 percent of the load-weighted LMP was the result of up-to congestion transactions, 11.9 percent was the result of the cost of coal and 5.7 percent was the result of the cost of gas.

Table 3-67 Components of PJM day-ahead, (unadjusted) annual, load-weighted, average LMP (Dollars per MWh): 2012 and 2013[73]

	2012		2013		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Up-to Congestion Transaction	$1.69	4.9%	$28.00	71.9%	67.0%
Coal	$13.60	39.4%	$4.63	11.9%	(27.5%)
Gas	$4.60	13.3%	$2.21	5.7%	(7.6%)
DEC	$8.17	23.7%	$1.89	4.9%	(18.8%)
INC	$3.33	9.7%	$1.31	3.4%	(6.3%)
Ten Percent Cost Adder	$2.02	5.9%	$0.74	1.9%	(4.0%)
VOM	$1.54	4.5%	$0.50	1.3%	(3.2%)
Dispatchable Transaction	$0.53	1.5%	$0.13	0.3%	(1.2%)
FMU Adder	$0.01	0.0%	$0.08	0.2%	0.2%
Price Sensitive Demand	$0.45	1.3%	$0.05	0.1%	(1.2%)
NO_x	$0.06	0.2%	$0.02	0.1%	(0.1%)
CO_2	$0.06	0.2%	$0.02	0.0%	(0.1%)
DASR LOC Adder	($0.31)	(0.9%)	$0.01	0.0%	0.9%
SO_2	$0.01	0.0%	$0.00	0.0%	(0.0%)
Oil	$0.35	1.0%	$0.00	0.0%	(1.0%)
DASR Offer Adder	$0.15	0.4%	$0.00	0.0%	(0.4%)
Constrained Off	$0.00	0.0%	$0.00	0.0%	(0.0%)
Wind	($0.00)	(0.0%)	($0.00)	(0.0%)	(0.0%)
Markup	($1.86)	(5.4%)	($0.78)	(2.0%)	3.4%
Diesel	$0.00	0.0%	$0.00	0.0%	(0.0%)
NA	$0.14	0.4%	$0.11	0.3%	(0.1%)
Total	$34.55	100.0%	$38.93	100.0%	

Table 3-68 shows the components of the PJM day ahead, annual, load-weighted average LMP including the adjusted markup calculated by excluding the 10 percent adder from the coal units.

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

73 PJM acknowledged an error in identifying marginal up-to congestion transactions following April 2013 changes to the day-ahead solution software. The software incorrectly increased the volume of marginal up-to congestion transactions. The fix to the problem is expected to be in place in 2014.

Table 3-68 Components of PJM day-ahead, (adjusted) annual, load-weighted, average LMP (Dollars per MWh): 2012 and 2013

	2012		2013		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Up-to Congestion Transaction	$1.69	4.9%	$28.00	71.9%	67.0%
Coal	$13.60	39.4%	$4.63	11.9%	(27.5%)
Gas	$4.60	13.3%	$2.21	5.7%	(7.6%)
DEC	$8.17	23.7%	$1.89	4.9%	(18.8%)
INC	$3.33	9.7%	$1.31	3.4%	(6.3%)
VOM	$1.54	4.5%	$0.50	1.3%	(3.2%)
Ten Percent Cost Adder	$1.02	2.9%	$0.48	1.2%	(1.7%)
Dispatchable Transaction	$0.53	1.5%	$0.13	0.3%	(1.2%)
FMU Adder	$0.01	0.0%	$0.08	0.2%	0.2%
Price Sensitive Demand	$0.45	1.3%	$0.05	0.1%	(1.2%)
NO_x	$0.06	0.2%	$0.02	0.1%	(0.1%)
CO_2	$0.06	0.2%	$0.02	0.0%	(0.1%)
DASR LOC Adder	($0.31)	(0.9%)	$0.01	0.0%	0.9%
SO_2	$0.01	0.0%	$0.00	0.0%	(0.0%)
Oil	$0.35	1.0%	$0.00	0.0%	(1.0%)
DASR Offer Adder	$0.15	0.4%	$0.00	0.0%	(0.4%)
Constrained Off	$0.00	0.0%	$0.00	0.0%	(0.0%)
Wind	($0.00)	(0.0%)	($0.00)	(0.0%)	(0.0%)
Markup	($0.85)	(2.5%)	($0.53)	(1.4%)	1.1%
Diesel	$0.00	0.0%	$0.00	0.0%	(0.0%)
NA	$0.14	0.4%	$0.11	0.3%	(0.1%)
Total	$34.55	100.0%	$38.93	100.0%	

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 Energy 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 on a day to day basis is not a realistic expectation as a result of uncertainty, lags in response time and modeling differences, such as differences in modeled contingencies and marginal loss calculations, between the Day-Ahead and Real-Time Energy Market.

Where arbitrage opportunities are created by differences between Day-Ahead and Real-Time Energy Market expectations, the resulting behavior can lead to more efficient market outcomes by improving day-ahead commitments relative to real-time system requirements.

But there is no guarantee that the results of virtual bids and offers will result in more efficient market outcomes.

Where arbitrage incentives are created by systematic modeling differences, such as differences between the day-ahead and real-time modeled transmission contingencies and marginal loss calculations, virtual bids and offers cannot result in more efficient market outcomes. Such offers may be profitable but cannot change the underlying reason for the price difference. The virtual transactions will continue to profit from the activity for that reason. This is termed false arbitrage.

INCs, DECs and UTCs allow participants to arbitrage price differences between the Day-Ahead and Real-Time Energy Market. Absent a physical position in real time, the seller of an INC must buy energy in the Real-Time Energy Market to fulfill the financial obligation to provide energy. If the day-ahead price for energy is higher than the real-time price for energy, the INC makes a profit. Absent a physical position in real time, the buyer of a DEC must sell energy in the Real-Time Energy Market to fulfill the financial obligation to buy energy. If the day-ahead price for energy is lower than the real-time price for energy, the DEC makes a profit.

While the profitability of an INC or DEC position is an indicator that the INC or DEC, all else held equal, contributed to price convergence at the specific bus, unprofitable INCs and DECs may also contribute to price convergence.

Profitability is a less reliable indicator of whether a UTC contributes to price convergence than for INCs and DECs. The profitability of a UTC transaction is the net of the separate profitability of the component INC and DEC. A UTC can be net profitable if the profit on one side of the UTC transaction exceeds the losses on the other side. A profitable UTC can contribute to both price divergence on one side and to price convergence on the other side.

Table 3-69 shows the number of cleared UTC transactions, the number of profitable cleared UTCs, the number of cleared UTCs that were profitable at their source point and the number of cleared UTCs that were profitable at their sink point in 2012 and 2013. In 2013, 55.4 percent of all cleared UTC transactions were net profitable, with 67.1 percent of the source side profitable and 39.4 percent of the sink side profitable (Table 3-69).

Table 3-69 Cleared UTC profitability by source and sink point: 2012 and 2013[74]

Year	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	Profitable UTC	Profitable Source	Profitable Sink
2012	9,053,260	4,908,131	5,627,266	3,567,325	54.2%	62.2%	39.4%
2013	14,736,798	8,162,744	9,883,565	4,994,347	55.4%	67.1%	33.9%

PJM performed a study (May Study) of market results for May 2, 3, 22, 23 and 27, with and without UTCs using its day-ahead model.[75] The MMU used PJM's results from the May Study to analyze the effects of UTCs on price convergence.

Figure 3-29 Node hours, by hour, that day-ahead and real-time LMP was closer with or without UTC in PJM's May Study: May 2, 4, 22, 23 and 27

Due to multiple cleared UTCs sourcing and sinking concurrently at or near the same buses, the net effects of UTCs on the system model can provide results that do not match expectations when UTCs are examined on an individual bus basis. For example, while 75.1 percent of cleared UTC source points cleared consistent with day-ahead and real-time point specific (not spread) LMP arbitrage when examined on an individual UTC basis, PJM's results showed increased divergence between day-ahead and real-time LMP at 43.5 percent of UTC day-ahead source locations when UTCs were added. Similarly, while 27.5 percent of UTC sink points cleared consistent with day-ahead and real-time LMP arbitrage, PJM's results showed increased divergence between day-ahead and real-time LMP at 45.5 percent of cleared UTC day-ahead sink locations when UTCs were added.

Figure 3-29 shows total node hours, by hour, that day-ahead and real-time LMP was closer with or without UTC in PJM's results. The results do not support the assertion that UTC transactions contribute to node specific convergence between day-ahead and real-time prices. UTC transactions are associated with both convergence and divergence.

There are incentives to use virtual transactions to arbitrage price differences between the Day-Ahead and Real-Time Energy Markets, but there is no guarantee that such activity will result in price convergence and no data to support that claim. As a general matter, virtual offers and bids are based on expectations about both Day-Ahead and Real-Time Energy Market conditions and reflect the uncertainty about conditions in both markets and the fact that these conditions change hourly and daily. PJM markets do not provide a mechanism that could result in immediate convergence after a change in system conditions as there is at least a one day lag after any change in system conditions before offers could reflect such changes.

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 3-31).

Table 3-70 shows that the difference between the average real-time price and the average day-ahead price

74 Calculations exclude PJM administrative charges.
75 ALSTOM SPD program and unit commitment process.

was $0.32 per MWh in 2012 and -$0.60 per MWh in 2013. The difference between average on-peak real-time price and the average day-ahead price was $1.37 per MWh in 2012 and -$0.39 per MWh in 2013.

Table 3-70 Day-ahead and real-time average LMP (Dollars per MWh): 2012 and 2013[76]

	2012				2013			
	Day Ahead	Real Time	Difference	Difference as Percent of Real Time	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$32.79	$33.11	$0.32	1.0%	$37.15	$36.55	($0.60)	(1.6%)
Median	$30.89	$29.53	($1.36)	(4.6%)	$34.63	$32.25	($2.38)	(7.4%)
Standard deviation	$13.27	$20.67	$7.40	35.8%	$15.46	$20.57	$5.11	24.8%
Peak average	$38.46	$39.83	$1.37	3.4%	$43.63	$43.24	($0.39)	(0.9%)
Peak median	$34.71	$33.13	($1.58)	(4.8%)	$39.67	$36.75	($2.92)	(8.0%)
Peak standard deviation	$15.86	$25.47	$9.61	37.7%	$19.20	$25.69	$6.49	25.3%
Off peak average	$27.88	$27.29	($0.59)	(2.2%)	$31.50	$30.72	($0.78)	(2.5%)
Off peak median	$27.15	$26.18	($0.97)	(3.7%)	$30.19	$28.44	($1.76)	(6.2%)
Off peak standard deviation	$7.66	$12.74	$5.08	39.9%	$7.59	$11.99	$4.40	36.7%

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

Table 3-71 shows the difference between the Real-Time and the Day-Ahead Energy Market prices for each year of the 13-year period 2001 to 2013.

Table 3-71 Day-ahead and real-time average LMP (Dollars per MWh): 2001 through 2013

Year	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.3%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%
2010	$44.57	$44.83	$0.26	0.6%
2011	$42.52	$42.84	$0.32	0.7%
2012	$32.79	$33.11	$0.32	1.0%
2013	$37.15	$36.55	($0.60)	(1.6%)

Table 3-72 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for the years 2007 through 2013.

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

Table 3-72 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): 2007 through 2013[77]

	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%	1	0.01%	5	0.06%	4	0.05%
($150) to ($100)	0	0.00%	1	0.01%	0	0.00%	0	0.00%	2	0.03%	6	0.13%	5	0.10%
($100) to ($50)	33	0.38%	88	1.01%	3	0.03%	13	0.15%	49	0.59%	17	0.32%	9	0.21%
($50) to $0	4,600	52.89%	5,120	59.30%	5,108	58.34%	5,543	63.42%	5,614	64.68%	5,576	63.80%	5,994	68.63%
$0 to $50	3,827	96.58%	3,247	96.27%	3,603	99.47%	3,004	97.72%	2,880	97.56%	3,061	98.65%	2,659	98.98%
$50 to $100	255	99.49%	284	99.50%	41	99.94%	164	99.59%	185	99.67%	82	99.58%	64	99.71%
$100 to $150	31	99.84%	37	99.92%	5	100.00%	25	99.87%	21	99.91%	17	99.77%	12	99.85%
$150 to $200	5	99.90%	4	99.97%	0	100.00%	9	99.98%	2	99.93%	12	99.91%	10	99.97%
$200 to $250	1	99.91%	2	99.99%	0	100.00%	2	100.00%	3	99.97%	5	99.97%	1	99.98%
$250 to $300	3	99.94%	0	99.99%	0	100.00%	0	100.00%	0	99.97%	1	99.98%	2	100.00%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.97%	2	100.00%	0	100.00%
$350 to $400	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%	0	100.00%
$400 to $450	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%	0	100.00%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%	0	100.00%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%	0	100.00%

Figure 3-30 shows the hourly differences between day-ahead and real-time hourly LMP in 2013.

Figure 3-30 Real-time hourly LMP minus day-ahead hourly LMP: 2013[78]

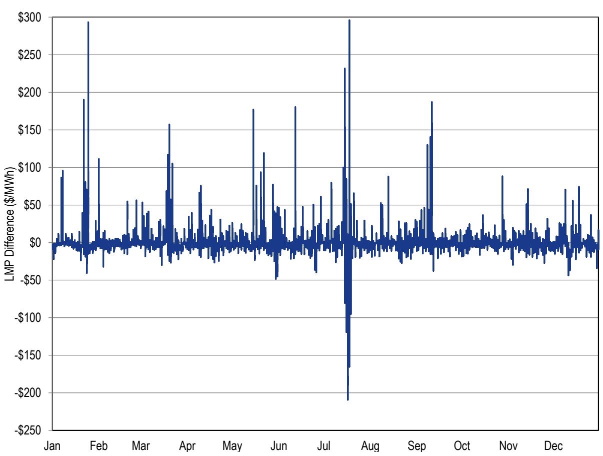
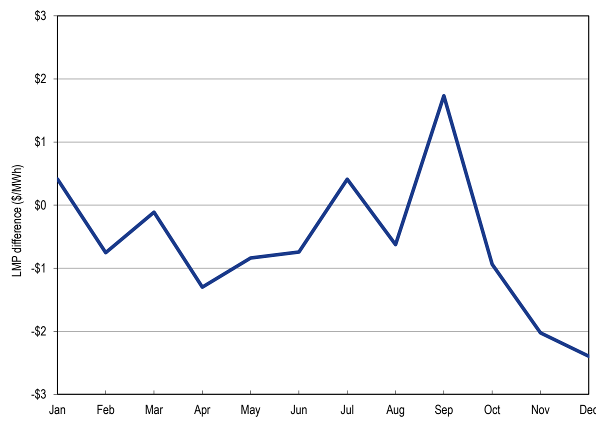


Figure 3-31 shows the monthly average differences between the day-ahead and real-time LMP in 2013.

Figure 3-31 Monthly average of real-time minus day-ahead LMP: 2013

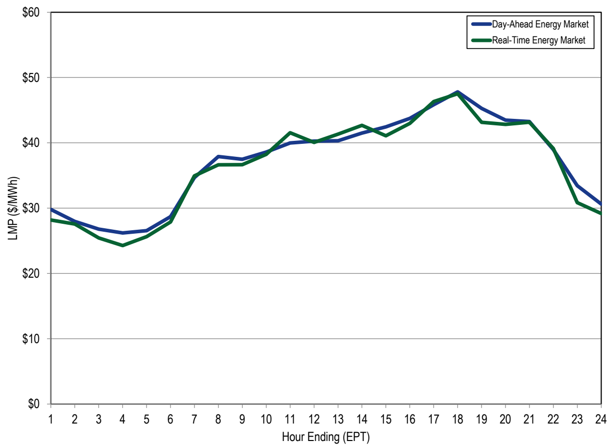


77 This table, which included "load-weighted" in its title in the *2013 State of the Market Report for PJM: January through September*, includes data on hourly prices for which "load-weighted" is not relevant.

78 This figure, which previously contained "load-weighted" in its description and title in the *2013 State of the Market Report for PJM: January through September*, has been updated to not include "load-weighted" in its title and description because the figure is about prices and not load.

Figure 3-32 shows day-ahead and real-time LMP on an average hourly basis for 2013.

Figure 3-32 PJM system hourly average LMP: 2013



Scarcity

PJM's Energy Market did not experience any reserve-based shortage events in 2013. However, hot weather alerts were declared on seventeen days in 2013 in all or parts of the PJM territory. Cold weather alerts were declared on seven days in 2013 in all or parts of the PJM territory. A maximum emergency generation alert was called on four days in 2013 and maximum emergency generation action was declared on five days in parts of PJM in 2013. Emergency demand resources were dispatched in parts of PJM on five days in 2013. A voltage reduction warning and reduction of non-critical plant load was issued on one day in 2013. During the week beginning September 9, PJM issued load shed directives in specific locations. This section addresses issues related to the emergency operations and extreme weather events in the PJM service territory in 2013.

Emergency Procedures in 2013

PJM declared hot weather alerts on 17 days in 2013 and 28 days in 2012.[79] The purpose of a hot weather alert is to prepare personnel and facilities for extreme hot and/or humid weather conditions. PJM communicates to members whether fuel limited resources are to be placed into maximum emergency category.

PJM declared cold weather alerts on seven days in 2013 and did not declare any cold weather alerts in 2012.[80] The purpose of a cold weather alert is to prepare personnel and facilities for expected extreme cold weather conditions, generally when temperatures are forecast to approach minimums or fall below ten degrees Fahrenheit.

PJM declared maximum emergency generation alerts on four days in 2013 and on one day in 2012. The purpose of a maximum emergency generation alert is to provide an alert at least one day prior to the operating day that system conditions may require use of PJM emergency procedures. It is called to alert PJM members that maximum emergency generation may be requested in the operating capacity.[81] This means that if PJM directs members to load maximum emergency generation during the operating day, the resources must be able to increase generation above the maximum economic level of their offer.

PJM declared emergency mandatory load management reductions (long lead time) on five days in 2013 and on two days in 2012. The purpose of emergency mandatory load management (long lead time) is to request curtailment service providers (CSP) to implement load reductions from demand resources registered in PJM demand response programs that have a lead time of between one and two hours.

PJM declared emergency mandatory load management reductions (short lead time) on one day each in 2013 and 2012. The purpose of emergency mandatory load management (short lead time) is to request curtailment service providers (CSP) to implement load reductions from demand resources registered in PJM demand response programs that have a lead time of up to one hour.

PJM declared maximum emergency generation actions on five days in 2013 and on two days in 2012. The purpose of a maximum emergency generation action is to request generators to increase output to the maximum emergency level which is above the maximum economic level. A maximum emergency generation action can be

79 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), Section 3.4 Hot Weather Alert, p. 44.

80 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), Section 3.3 Cold Weather Alert, p. 41.

81 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), Section 2.3.1 Day-Ahead Emergency Procedures: Alerts, p. 16.

issued for the entire RTO, for specific control zones or for parts of control zones.

PJM declared a voltage reduction warning and reduction of non-critical plant load on one day each in 2013 and 2012. The purpose of a voltage reduction warning and reduction of non-critical plant load is to warn members that actual synchronized reserves are less than the synchronized reserve requirement and that a voltage reduction may be required. It can be issued for the entire RTO or for specific control zones.

Table 3-73 provides a description of PJM declared emergency procedures.

Table 3-73 Description of Emergency Procedures

Emergency Procedure	Purpose
Cold Weather Alert	To prepare personnel and facilities for extreme cold weather conditions, generally when forecast weather conditions approach minimum or temperatures fall below ten degrees Fahrenheit.
Hot Weather Alert	To prepare personnel and facilities if extreme hot and/or humid weather conditions, which may cause capacity requirements/unit unavailability to be substantially higher than forecast, are expected to persist for an extended period.
Maximum Emergency Generation Alert	To provide an early alert at least one day prior to the operating day that system conditions may require the use of the PJM emergency procedures and resources must be able to increase generation above the maximum economic level of their offers.
Emergency Mandatory Load Management Reductions (Long Lead Time)	To request end-use customers registered in the PJM demand response program as a demand resource (DR) that need between one to two hours lead time to make reductions.
Emergency Mandatory Load Management Reductions (Short Lead Time)	To request end-use customers registered in the PJM demand response program as a demand resource (DR) that need up to one hour lead time to make reductions.
Maximum Emergency Generation Action	To provide real time notice to increase generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the maximum economic level.
Voltage Reduction Warning & Reduction of Non-Critical Plant Load	To warn members that actual synchronized reserves are less than the synchronized reserve requirement and that voltage reduction may be required.

Table 3-74 shows the dates on which emergency procedures were implemented in 2013.

Table 3-74 PJM declared emergencies: 2013

Dates	Cold Weather Alert	Hot Weather Alert	Maximum Emergency Generation Alert	Maximum Emergency Generation Action	Emergency Mandatory Load Management Long Lead Time	Emergency Mandatory Load Management Short Lead Time	Voltage Reduction Warning and Reduction of Non-Critical Plant Load
1/21/2013	ComEd						
1/22/2013	PJM Western Region						
1/23/2013	PJM						
1/24/2013	PJM						
5/30/2013		Mid-Atlantic and Dominion					
5/31/2013		Mid-Atlantic and Dominion					
6/1/2013		Mid-Atlantic and Dominion					
6/13/2013		Dominion					
6/25/2013		Mid-Atlantic					
6/26/2013		Mid-Atlantic and Dominion					
7/15/2013		PJM except ComEd		ATSI	ATSI		
7/16/2013		PJM except ComEd	PJM	ATSI	ATSI		
7/17/2013		PJM except ComEd	PJM				
7/18/2013		PJM	PJM	AEP(Canton subzone), ATSI, PECO, PPL	AEP (Canton subzone), ATSI, PECO, PPL		
7/19/2013		PJM					
7/20/2013		Mid-Atlantic and Dominion					
8/26/2013		ComEd					
8/30/2013		ComEd					
9/9/2013		ComEd					
9/10/2013		PJM Western Region		ATSI	AEP (Canton subzone), ATSI		
9/11/2013		PJM	PJM	AEP, ATSI, DLCO, Mid-Atlantic and Dominion	AEP, ATSI, DLCO, Mid-Atlantic and Dominion	Mid-Atlantic	AEP, ATSI
12/12/2013	PJM						
12/30/2013	ComEd						
12/31/2013	ComEd						

Load Shed Events in September

In the week beginning September 9, 2013, unusually high temperatures resulted in emergency conditions in the PJM service territory which resulted in local reliability issues. In order to avoid potential cascading outages, PJM issued load shed directives in specific locations.[82] Table 3-75 contains a summary of the load shed events on September 9 and 10. In addition to the load shed events, there was a synchronized reserve event on September 10 to recover from a low area control error (ACE). The response of Tier 1 resources to the synchronized reserve event was significantly less than expected and the event lasted an hour and six minutes.

Table 3-75 Summary of load shed events in September 2013

Event	Date	Start and End Times (EPT)	Duration	Zone	Total MW
Pigeon River 1	9-Sep-13	1617 - 1631	14 min	AEP	3.1
		1249 - 2123	8 hr 34 min		5.0
Pigeon River 2	10-Sep-13	1314 - 2123	8 hr 9 min	AEP	3.0
FE Tod	10-Sep-13	1507 - 1642	1 hr 35 min	ATSI	16.0
		1741 - 0002(9/11)	6 hr 21 min		70.0
Penelec Erie South	10-Sep-13	1819 - 0002(9/11)	5 hr 43 min	Penelec	35.0
AEP Summit	10-Sep-13	1913 - 2016	1 hr 3 min	AEP	25.0

On September 9, at 1538, PJM directed AEP to shed 3.1 MW of load at the Pigeon River substation of AEP Zone in southern Michigan. The substation is at the 69kV level, below the level where PJM monitors and controls, but the loss of a 138 kV line (East Elkhart-Mottville Tap-Mottville-Corey 138-kV line) that feeds the load pocket would have triggered a voltage collapse in the area and a potential cascading event. The load was restored at 1631.

On September 10, PJM directed AEP to shed eight MW of load (five MW at 1249 and an additional three MW

82 For a detailed assessment of the load shed events, see PJM. "Technical Analysis of Operational Events and Market Impacts During the September 2013 Heat Wave" (December 23, 2013), pp 11-38.

at 1314) at the Pigeon River substation. The conditions from September 9 remained, with higher loads recorded in AEP on September 10. PJM directed a pre-contingency load shed to avoid a potential cascading event. The load was restored at 2123 on September 10.

On September 10, at 1501, PJM directed ATSI to shed 16 MW of load at the Tod 138 kV substation in the ATSI Zone. On September 9, at 1849, the South Canton #1 345/138 kV transformer tripped and resulted in the loss of four 345 kV lines at South Canton. Two of the lines were restored on the morning of September 10 at 0834. At 1350 on September 10, PJM issued long lead emergency load management in the ATSI Zone and the AEP South Canton subzone. In order to avoid a potential cascading event, PJM directed ATSI to shed 16 MW of load at the Tod station. The load was restored after the South Canton #1 transformer was returned to service.

On September 10, at 1739, PJM directed FirstEnergy to shed 105 MW of load in the FirstEnergy Penelec Zone near Erie, PA in increments of 70 MW at 1749 and an additional 35 MW at 1822. The unplanned loss of Seneca #1 hydro unit on September 9 at 2139, Seneca #2 hydro unit on September 10 at 1010 and the Erie West – Ashtabula – Perry 345 kV line on September 10 at 1336 meant that at 1659, PJM's power flow study indicated a potential post-contingency voltage collapse. The load was restored by 0002 on September 11.

On September 10, at 1913, PJM directed AEP to shed 25 MW of load in the Fort Wayne, IN area. The Summit – Industrial 138 kV line is a monitored priority 2 (MP2) facility which means that PJM can manually redispatch generation to relieve an overload on the line only at the request of the Transmission Owner and the generation does not set price.[83] PJM issued a post contingency local load relief warning (PCLLRW) at 1146 to alert the TO that it would need to shed load within five minutes if the Robison Park T5 transformer were to trip. At 1850, AEP notified PJM that the post contingency flow on the Industrial – Summit 138 kV line was 20MVA higher than PJM's post contingency analysis indicated and that it exceeded 115 percent of the load dump limit. At 1913, PJM directed AEP to shed 25 MW of load in the Summit area. The load was restored at 2016.

Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, plus reserve requirements, is nearing the limits of the available capacity of the system. Under the PJM rules that were in place through September 30, 2012, high prices, or scarcity pricing, resulted from high offers by individual generation owners for specific units when the system was close to its available capacity. But this was not an efficient way to manage scarcity pricing and made it difficult to distinguish between market power and scarcity pricing.

On October 1, 2012, PJM introduced a new administrative scarcity pricing regime. Under the current PJM market rules, shortage pricing conditions are triggered when there is a shortage of synchronized or primary reserves in the RTO or in the Mid-Atlantic and Dominion (MAD) subzone. In times of reserve shortage, the cost of foregone reserves, reflected as a penalty factor in the optimization, is reflected in the price of energy.

Designation of Maximum Emergency MW

During extreme system conditions, when PJM declares maximum emergency generation alerts, the PJM tariff specifies that capacity can only be designated as maximum emergency if the capacity has limitations on its availability based on environmental limitations, short term fuel limitations, or emergency conditions at the unit, or the additional capacity is obtained by operating the unit past its normal limits.[84,85] The intent of the rule regarding maximum emergency designation is to ensure that only capacity with a clearly defined short term issue limiting its economic availability is defined as maximum emergency MW, which can be made available, at PJM's direction, to maintain the system during emergency conditions.

Declarations of hot/cold weather alerts also affect declarations of maximum emergency capacity under the rules. Hot weather alerts are issued when the system is expected to experience possible resource adequacy issues as a result of forecast consecutive days with projected temperatures in excess of 90 degrees with high humidity. Cold weather alerts are issued when the system

83 See PJM. "Manual 12: Balancing Operations," Revision 30 (December 1, 2013), Attachment B.3 Analyzing and Controlling Non-Market BES Facilities, p. 79.

84 See PJM OATT, 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.

85 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), p. 74.

is expected to experience possible resource adequacy issues as a result of forecast temperatures below ten degrees Fahrenheit.[86] A hot/cold weather alert indicates conditions that require that combustion turbine (CT) and steam units with limited fuel availability need to be removed from economic availability and made available as emergency only capacity.[87] The hot/cold weather alert rule defines specific criteria to use to determine fuel limited generation, thereby classifying that part of the capacity of a unit as maximum emergency generation. The hot/cold weather alert rule regarding maximum emergency capacity declarations, as outlined in Manual 13, is consistent with the maximum emergency alert rule and its intent.[88] The rule also prevents the misclassification of units or a portion of their capacity as maximum emergency and resultant physical withholding under the defined conditions.

There are incentives to keep capacity incorrectly designated as maximum emergency. Capacity designated as maximum emergency is considered as available, not on outage, even during the peak five hundred hours of the year defined in RPM. Capacity designated as maximum emergency is substantially less likely to be dispatched than capacity with an economic offer on high load days.

The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[89]

Emergency Operations

Prior to June 2013, PJM issued a post contingency local load relief warning (PCLLRW) if it projected the post contingency flows on a facility to exceed 115 percent of the load dump limit. Following PJM's review of the Southwest cascading outage that occurred in September 2011, PJM updated emergency operation procedures to implement a cascading outage analysis in June 2013.[90] After June 2013, the post contingency load dump limit exceedance analysis was incorporated in emergency operations to study possible cascading events. If PJM's security analysis indicates that post contingency flows on a facility are projected to exceed the 15-minute load dump rating, PJM will perform up to an N-5 contingency analysis. If the analysis indicates a non-converged case or that flows exceed 115 percent of load dump limits on any additional facilities, PJM will direct a pre-contingency load shed to prevent a potential cascading outage.

In light of the updated emergency procedures, the outage impact studies and planning studies should be updated to identify these reliability issues. It is not clear how PJM's outage impact studies have incorporated the stronger reliability criteria.[91,92] It is not clear how PJM's reliability analysis which directly affects key RPM parameters has incorporated the stronger reliability criteria.

The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013.

PJM-Transmission Owner Coordination

The AEP Summit load shed event on September 10, 2013, illustrated an issue related to the coordination between PJM and the local transmission owner (TO) in monitoring MP2 transmission facilities. The Summit – Industrial 138 kV line is a monitored priority 2 (MP2) facility which means that PJM can only manually redispatch generation to relieve an overload on the line at the request of the TO. The TO must pay the cost of the generation and the dispatched generation does not set price. MP2 facilities are not modeled in PJM's congestion management and LMP model.[93]

PJM saw post contingency flows on the Industrial – Summit 138 kV line exceed the 251 MVA limit and issued a post contingency local load relief warning (PCLLRW) at 1146. The purpose of the PCLLRW was to alert the TO that it would need to shed load within five minutes if the Robison Park T5 transformer were to trip. It is not clear whether the TO requested that PJM manually

86 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), p. 41.
87 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), p. 86.
88 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), pp 73-74.
89 See PJM OATT, 6A.1.3 Maximum Emergency, (February 25, 2014) p. 1740, 1796.
90 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), Section 5.4.1 Post Contingency Load Dump Limit Exceedance Analysis, p. 77.
91 See PJM. "Manual 14b: PJM Region Transmission Planning Process," Revision 25 (October 24, 2013) Section 2.3.8 NERC Category C3 "N-1-1" Analysis, p. 25.
92 See PJM. "Manual 14b: PJM Region Transmission Planning Process," Revision 25 (October 24, 2013) Section 2.7 Evaluation of Operational Performance Issues, p. 38.
93 See PJM. "Manual 12: Balancing Operations," Revision 30 (December 1, 2013), Attachment B.3 Analyzing and Controlling Non-Market BES Facilities, p. 79.

redispatch generation to address the issue on the MP2 facility. If there is potential for an MP2 contingency to lead to a cascading event that could affect the reliability of the bulk electric system, the decision should not be made by the transmission owner.

The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent.

Definition of ATSI Constraint

The ATSI Interface was created by PJM effective July 17, 2013. It is not an interconnection reliability operating limit (IROL) transfer interface, which includes reactive transfer interfaces, nor does it reflect actual thermal transmission limits. The ATSI Interface, comprised of all the tie lines into the ATSI Control Zone,[94] was created by PJM in order to let emergency demand resources set real time prices in the ATSI Control Zone. The creation of the ATSI Interface allows demand resources (DR) dispatched in the ATSI Control Zone to be marginal for providing energy during real-time emergency operations. The ATSI Interface is not defined or modeled in the Day-Ahead Energy Market and it cannot be defined in the Day-Ahead Energy Market because Emergency DR is not in the Day-Ahead Energy Market.

The ATSI Interface was binding in real time for three hours on July 18, seven hours on September 10 and eight hours on September 11. For 12 of these 18 hours, the hourly ATSI zonal LMP was between $1,795 and $1,803 per MWh and for 16 of these 18 hours it was greater than $1,000.

PJM created the ATSI Interface with the goal of reflecting PJM operator actions in the LMP in the ATSI Control Zone which means operators calling on emergency demand response.[95] The ATSI Interface is a closed loop interface, which means that only the capacity available inside of the ATSI Control Zone can relieve the constraint and capacity available outside of the ATSI Control Zone cannot relieve the constraint.[96]

Unlike generators, emergency demand resources are not identified by node, instead, they are aggregated by zone. During the 2013/2014 Delivery Year, subzonal dispatch of demand resources was available only on a voluntary basis and required that a subzone be defined before the dispatch day. Zonal dispatch was mandatory.[97] To achieve a mandatory curtailment, PJM must call all demand resources in a zone. PJM does not have the information available to permit a more targeted call. PJM does not have information on the nodal location of demand resources and does not have information on the impact that demand resources would have had (distribution factors) on specific transmission facilities. This limitation on the commitment of demand resources does not allow PJM dispatchers to estimate the impact of DR on specific constrained facilities and also means that DR cannot be used to set locational prices.

Whenever the ATSI Interface binds, energy prices at all the nodes within the ATSI Control Zone are set at the offer of the marginal resource within the ATSI Control Zone as a result of the definition of the ATSI Interface. This does not provide the locational price signals within the ATSI Control Zone to dispatch resources up or down to relieve constraints within the ATSI Control Zone. Therefore, PJM operators have to make manual dispatch decisions in order to keep the flows on facilities within the ATSI Control Zone below their limits. This problem was evident on September 11 when a small number of units within the ATSI Control Zone were dispatched down in order to control the flow on a line within the ATSI Control Zone. These units were paid energy uplift in the form of lost opportunity cost credits because these units were instructed not to operate at full output although their offers were significantly lower than the $1,800 per MWh LMP set by Emergency demand resources. Since the ATSI Interface is not modeled in the Day-Ahead Energy Market but only during real-time peak load conditions, when the ATSI Interface was binding the result was negative balancing congestion and a negative impact on FTR revenue adequacy in July and September.

The MMU agrees that operators' decisions should be reflected in pricing, but only within the nodal pricing framework. Incorporating a closed loop interface is not

94 See PJM. "ATSI Interface" <http://www.pjm.com/~/media/etools/oasis/system-information/atsi-interface-definition-update.ashx>

95 See PJM. "Hot Weather Operations (July 2013) Questions, Comments and Responses" (August 28, 2013), p. 2.

96 See the *2013 State of the Market Report for PJM*, Section 4: Energy Uplift, at "Closed-loop Interfaces".

97 See PJM. "Manual 18: PJM Capacity Market," Revision 20 (November 21, 2013), Section 9.1.9 Demand Response Compliance Penalty Charge, p. 139.

a substitute for addressing the underlying issue, which is the inflexibility of DR and the lack of nodal DR dispatch among other issues. PJM should not have the authority to decide when energy prices should be high in an entire zone, yet that is what PJM did when it established the ATSI Interface. The MMU recommends that PJM not use the ATSI Interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product. Market prices should be a function of market fundamentals.

The MMU continues to recommend that demand resource dispatch be nodal to permit more effective dispatch of such resources, that demand resources be required to make day-ahead offers, that demand resources be considered an economic resource rather than an emergency resource, that demand resources be available year round and that demand resources have a shorter lead time.[98,99] The requirement for an announcement of emergency conditions, two hour lead time, two hour minimum dispatch period, availability of demand resources only from 12:00-20:00, maximum number of events allowed each delivery year, maximum of hours per event, and lack of nodal mapping are inappropriate limitations on demand resources that should be removed in order to ensure that demand resources serve as capacity resources and are available to resolve reliability issues when necessary. When DR is treated like other capacity resources, LMP will be set according to the market rules and will appropriately reflect market conditions.

Transmission facility ratings

For the South Canton #3 transformer, AEP reviewed the ratings and found an error in their database on July 17, 2013. The most restrictive rating (normal) was revised from 1,718 MVA to 1,852 MVA. Having a lower rating on a facility would have led to dispatch of out of merit resources earlier than necessary. In the Pigeon River load shed events in southern Michigan on September 9 and 10, PJM was notified of the relay trip rating on the Lagrange - Howe 69 kV line in the Northern Indiana Public Service Corp (NIPSCO) territory within MISO for the first time on September 9. Prior to September 9, PJM was not aware of a relay trip rating on the line and it was not modeled in PJM's energy management system.

In the load shed event in Ft. Wayne, Indiana on September 10, ratings on the Summit – Industrial 138 kV line were the same for normal (24 hours), emergency (4 hours) and load dump (15 minute) levels. In May 2013, AEP changed the load dump rating on the Summit – Industrial 138 kV line from 289 MVA to 251 MVA until the line could be resagged. Resagging is necessary when a line sags due to heat and the distance between the line and any obstruction does not meet the minimum required clearance. As the other line ratings were not changed concurrently, ratings on the Summit – Industrial 138 kV line were the same for normal, emergency and load dump levels at 251 MVA.

During real-time emergency operations on September 10, there was a discrepancy between the overloads in AEP's power flow analysis and PJM's state estimator. This discrepancy was a result of modeling differences between PJM and AEP. A pseudo-series device modeled at Industrial in PJM's state estimator model should have had zero impedance and therefore no impact on the state estimator solution. But PJM's model had a non-zero impedance value and the estimated post-contingency flows on the Summit – Industrial line for the loss of the Robison Park T5 transformer were 20 MVA lower than AEP's correct solution indicated. The post contingency flows on the Summit – Industrial line (for the loss of the Robison Park T5 345/138 kV transformer) observed in the day-ahead case were within an acceptable limit (86 percent of the load dump limit). The modeling error (along with inaccurate load forecast) contributed to the lower observed post contingency flows in the day-ahead case. PJM has resolved this issue.

It is critical to both reliability and market outcomes that dispatchers have accurate transmission facility ratings. The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice.

Behind the Meter Generation

In the Pigeon River load shed event on September 9 and 10, both PJM and AEP were unaware of the six MW behind the meter (BTM) generator in the city of

98 See the *2013 State of the Market Report for PJM*, Section 6, "Demand Response" at "Recommendations".
99 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014).

Sturgis. The generator was not modeled in the energy management systems of PJM and AEP. This unit had a 67 percent distribution factor on the post contingency flow on the LaGrange - Howe 69 kV line. If the unit had been generating, it would have avoided the load shed on September 9 and reduced the amount of load shed on September 10 in the Pigeon River area. AEP personnel identified the unit in preparation for September 11 and notified the city of Sturgis about the PJM system emergency. On September 11, the unit was started and produced 5.4 MW of energy. The combination of the unit and voluntary customer load curtailment initiated by the city of Sturgis provided enough relief to prevent pre contingency load shed in the Pigeon River area on September 11.

The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters.

Interchange Transactions

On July 18, 2013, PJM issued emergency mandatory load management in the ATSI, PECO and PPL zones at 1240 and in AEP's South Canton subzone at 1300. Long lead demand response has a two hour notification time. These actions were based on the expectation that demand resources would be required to be dispatched to maintain sufficient reserves over the peak. In hour ending 1400, the RTO system marginal price reached $464.88, which provided a signal for market participants to import energy into PJM from neighboring balancing authorities. At that time, PJM's MISO interface price (the price a transaction receives from PJM for imports from MISO or pays to PJM to export to MISO) was $397.24, while MISO's PJM interface price (the price a transaction pays to MISO to export to PJM or receives from MISO for an import from PJM) was $48.97, and PJM's NYISO interface price (the price a transaction receives from PJM for imports from NYISO or pays to PJM to export to NYISO) was $503.16, while NYISO's PJM interface price (the price a transaction pays to NYISO to export to PJM or receives from NYISO for an import from PJM) was $154.80.

By 1500, net interchange imports into PJM increased by more than 3,000 MW, from 4,686 MW in hour ending 1400 to 7,692 MW in hour ending 1500. The RTO system marginal price in hour ending 1500 dropped to $52.17. At that time, the PJM's MISO interface price dropped to $31.28, while MISO's PJM interface price increased slightly to $59.01, and PJM's NYISO interface price dropped to $73.46, while NYISO's PJM interface price increased to $325.80. While PJM continued to be a net importer of energy, net imports to PJM gradually declined in the following hours as market participants responded to the lower prices. By hour ending 2000, net imports were reduced to 5,804 MW, a 1,888 MW reduction from the imports observed in hour ending 1500.

When PJM prices are higher than prices in surrounding balancing authorities, imports will flow into PJM until the prices are approximately equal. This is an appropriate market response to price differentials. Given the nature of interface pricing and the treatment of interface transactions, it is not possible to reliably predict the quantity or sustainability of imports. In addition to changing prices, transmission line loading relief procedures (TLRs), market participants' curtailments for economic reasons, and external balancing authority curtailments all affect the duration of interchange transactions. Real-time interchange transactions can be submitted with 20 minutes notice.

Emergency demand resources must be called two hours in advance. At the time the decision needs to be made to call for demand resources, the expected interchange is not known.

Optimizing interchange between neighboring balancing authorities could resolve many of the issues observed during high-load days. The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule physical power. Such a solution would include an optimized joint dispatch approach that treats seams between balancing authorizes as a constraint, similar to any other constraint within an LMP market. In addition, implementing a more flexible demand response program that requires a shorter lead time, and shorter minimum response times would also reduce the need to call for demand resources when not necessary.