Energy Market

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for the first three months of 2014, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM Energy Market results were competitive in the first three months of 2014.

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 the first three months of 2014 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1133 with a minimum of 956 and a maximum of 1378 in the first three months of 2014.
- 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, although the behavior of some participants during the high demand periods in January raises concerns about economic withholding.
- 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. Issues related to the definition of gas costs includable in offers and the impact of the uncertainty around gas costs during high demand periods also need to be addressed.

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

1 Analysis of 2014 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.

basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[3] There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are extremely tight.

Overview

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. Average offered real-time generation decreased by 273 MW, or 0.2 percent, from 177,820 MW in the first three months of 2013 to 177,547 MW in the first three months of 2014.[4] In 2014, 271 MW of new capacity were added to PJM. This new generation was mostly offset by the deactivation of 4 units (208 MW) since January 1, 2014. The decrease in offered supply in the first three months of 2014 was in part a result of a 1,866 MW reduction in net capacity between April 2013 and March 2014.[5]

  PJM average real-time generation in the first three months of 2014 increased by 8.5 percent from the first three months of 2013, from 92,776 MW to 100,655 MW. The PJM average real-time generation in the first three months of 2014 would have increased by 7.7 percent from the first three months of 2013, from 92,776 MW to 99,875 MW, if the EKPC Transmission Zone had not been included.[6]

  PJM average day-ahead supply in the first three months of 2014, including INCs and up-to congestion transactions, increased by 14.3 percent from the first three months of 2013, from 147,246 MW to 168,373 MW. The PJM average day-ahead supply, including INCs and up-to congestion transactions, would have increased by 13.7 percent from the first three months of 2013, from 147,246 MW to 167,394 MW, if the EKPC Transmission Zone had not been included. The day-ahead supply growth was 68.2 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 the first three months of 2014, coal units provided 48.6 percent, nuclear units 31.6 percent and gas units 14.7 percent of total generation. Compared to the first three months of 2013, generation from coal units increased 18.6 percent, generation from nuclear units decreased 3.6 percent, and generation from gas units increased 5.8 percent.

- **Marginal Resources.** In the PJM Real-Time Energy Market, during the first three months of 2014, coal units were 46.9 percent and natural gas units were 42.9 percent of marginal resources. In the first three months of 2013, coal units were 57.7 percent and natural gas units were 32.4 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market, during the first three months of 2014, up-to congestion transactions were marginal for 94.7 percent of marginal resources, INCs were marginal for 1.1 percent of marginal resources, DECs were marginal for 1.6 percent of marginal resources, and generation resources were marginal in only 2.4 percent of marginal resources.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM system peak load during the first three months of 2014 was 140,467 MW in the HE 1900 on January 7, 2014, the highest of

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 net capacity additions are calculated by taking the different between the new generation (1,036 MW) and the retired generation (2,902 MW) after April 1, 2013.

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

any winter since the introduction of PJM LMP markets on April 1, 1999 (Table 3-14).

PJM average real-time load in the first three months of 2014 increased by 7.6 percent from the first three months of 2013, from 91,337 MW to 98,317 MW.

PJM average day-ahead demand in the first three months of 2014, including DECs and up-to congestion transactions, increased by 13.5 percent from the first three months of 2013, from 143,585 MW to 163,031 MW. The day-ahead demand growth was 77.6 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. For the first three months of 2014, 9.5 percent of real-time load was supplied by bilateral contracts, 27.5 percent by spot market purchases and 63.0 percent by self-supply. Compared with 2013, reliance on bilateral contracts decreased 1.1 percentage points, reliance on spot market purchases increased by 2.5 percentage points and reliance on self-supply decreased by 1.4 percentage points.

- **Supply and Demand: Scarcity.** In the first three months of 2014, shortage pricing was triggered on two days in PJM. On January 6, shortage pricing was triggered by a voltage reduction action that was issued at 1950 EPT and terminated at 2045. On January 7, shortage pricing was triggered by shortage of primary and synchronized reserves starting in the hour beginning 0700 EPT and was in effect until 1220 during the morning peak as well as between 1755 and 1810 during the evening peak.

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 increased from 0.1 percent in the first three months 2013 to 0.3 percent in the first three months of 2014. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.3 percent in the first three months of 2013 to 1.1 percent in the first three months of 2014.

  In the first three months of 2014, 16 control zones experienced congestion resulting from one or more constraints binding for 25 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.

- **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 decreased from 3.0 percent in the first three months of 2013 to 0.5 percent in the first three months of 2014. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 2.4 percent in the first three months of 2013 to 0.4 percent in the first three months of 2014.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the PJM Real-Time Energy Market in the first three months of 2014, 58.3 percent of marginal units had an average markup index less than or equal to 0.0. Nonetheless, some marginal units do have substantial markups. In the first three months of 2014, 14.3 percent of units had average dollar markups greater than or equal to $150. By comparison, only 4.1 percent of units had average dollar markups greater than or equal to $150 in the first three months of 2013. Markups increased during the high demand days in January.

  In the PJM Day-Ahead Energy Market in the first three months of 2014, 86.6 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.03. Nonetheless, some marginal units do have substantial markups.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 93 units eligible for FMU or AU status in at least one month during the first three months of 2014, 67 units (72.0 percent) were FMUs or AUs for all three months, and 11 units (11.8 percent) qualified in only one month in the first three months of 2014.
- **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 the first three months of 2014, up-to congestion transactions continued to displace increment offers and decrement bids.
- **Generator Offers.** Generator offers are categorized as dispatchable and self scheduled. Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are categorized as self-scheduled must run. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are categorized as self scheduled and dispatchable. Of all generator offers in the first three months of 2014, 54.4 percent were offered as available for economic dispatch and 45.6 percent were offered as self scheduled.

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 Market prices in the first three months of 2014 were between $800 and $900 for 4 hours, between $900 and $1,000 for 1 hour, and greater than $1,000 for 6 hours.

  PJM Real-Time Energy Market prices increased in the first three months of 2014 compared to the first three months of 2013. The load-weighted average LMP was 148.5 percent higher in the first three months of 2014 than in the first three months of 2013, $92.98 per MWh versus $37.41 per MWh.

  PJM Day-Ahead Energy Market Prices increased in the first three months of 2014 compared to the first three months of 2013. The load-weighted average LMP was 154.9 percent higher in the first three months of 2014 than in the first three months of 2013, $94.97 per MWh versus $37.26 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 and it is possible to decompose PJM system's load-weighted LMP by the components of unit offers.

  In the PJM Real-Time Energy Market, for the first three months of 2014, 20.8 percent of the load-weighted LMP was the result of coal costs, 40.2 percent was the result of gas costs and 1.05 percent was the result of the cost of emission allowances. The first three months of 2014 was the first time since 2008 that the cost of gas accounted for a higher percentage of the load-weighted LMP than the cost of coal.

  In the PJM Day-Ahead Energy Market, for the first three months of 2014, 26.5 percent of the load-weighted LMP was the result of the cost of gas, 20.0 percent was the result of the cost of up-to congestion transactions and 13.2 percent was the result of the cost of INC.

- **Markup.** The markup conduct of individual owners and units has an identifiable 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 for the first three months of 2014, the adjusted markup component of LMP was positive, $7.12 per MWh or 7.3 percent of the PJM real-time, load-weighted average LMP. The real time load-weighted average LMP for the month of January had the

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."

highest markup component, $8.12 per MWh using adjusted cost offers. This corresponds to 6.4 percent of the real time load-weighted average LMP in January, a substantial increase over 2013. For the first three months of 2013, the adjusted markup was $0.13 per MWh or 0.3 percent of the PJM real-time load-weighted average LMP.

In the PJM Day-Ahead Energy Market, marginal INC, DEC and transactions have zero markups. In the first three months of 2014, the adjusted markup component of LMP resulting from generation resources was $0.73 per MWh.

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, although the behavior of some participants during the high demand periods in January raises concerns about economic withholding.

- **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 the average day-ahead and real-time prices was -$0.13 per MWh in the first three months of 2013 and -$2.48 per MWh in the first three months of 2014. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

- In the first three months of 2014, shortage pricing was triggered on two days in January. On January 6, shortage pricing was triggered by a voltage reduction action that was issued at 1950 EPT and terminated at 2045. On January 7, shortage pricing was triggered by a shortage of primary and synchronized reserves starting in the hour beginning 0700 EPT and was in effect until 1220 during the morning peak as well as between 1755 and 1810 during the evening peak.
- The performance of the PJM markets under scarcity conditions raised a number of concerns including concerns related to capacity market incentives, participant offer behavior under tight market conditions, natural gas availability and pricing, demand response and interchange transactions.

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

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.

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 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.
- The LMPs in excess of $1,800 per MWh on January 7, 2014, were potentially a result of the way in which PJM modeled zonal (not nodal) demand response as a marginal resource. The MMU recommends that PJM explain how LMPs are calculated when demand response is marginal.
- The MMU recommends that PJM create and implement clear, explicit and detailed rules in place that define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. The MMU recommends that PJM create and implement clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources.

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first three months of 2014, 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 decreased by 273 MW in the first three months of 2014 compared to the first three months of 2013, while peak load increased by 13,835 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 the impact of the price elasticity of demand on prices. Energy market results for the first three months of 2014 generally reflected supply-demand fundamentals, although the behavior of some participants during the high demand periods in January raises concerns about economic withholding.

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

These issues relate to the ability to increase markups substantially in tight market conditions, to the uncertainties about the pricing and availability of natural gas, and to the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel and operate rather than take an outage.

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 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, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case during the high demand hours in January. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods in January raises concerns about economic withholding. Given the structure of the Energy Market, the tighter markets and the change in some participants' behavior are sources of concern in the Energy Market. The MMU concludes that the PJM energy market results were competitive in the first three months of 2014.

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

Market Structure

Market Concentration

Analyses of supply curve segments of the PJM Energy Market for the first three months of 2014 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 the first three months of 2014.

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 the first three months of 2014 was moderately concentrated (Table 3-2).

Table 3-2 PJM hourly Energy Market HHI: January through March, 2013 and 2014[15]

	Hourly Market HHI (Jan - Mar, 2013)	Hourly Market HHI (Jan - Mar, 2014)
Average	1200	1133
Minimum	1047	956
Maximum	1409	1378
Highest market share (One hour)	28%	27%
Average of the highest hourly market share	21%	20%
# Hours	2,159	2,159
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-3 includes HHI values by supply curve segment, including base, intermediate and peaking plants for the first three months of 2013 and 2014.

Table 3-3 PJM hourly Energy Market HHI (By supply segment): 2013 and 2014

	Jan - Mar, 2013			Jan - Mar, 2014		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	1082	1205	1410	1024	1124	1324
Intermediate	1204	3526	8784	679	1863	8991
Peak	914	6987	10000	768	5898	10000

15 This analysis includes all hours in the first three months of 2014, regardless of congestion.

Figure 3-1 shows the number of units in the baseload, intermediate and peaking segments by fuel source in the first three months of 2014.

Figure 3-1 Fuel source distribution in unit segments: January through March, 2014

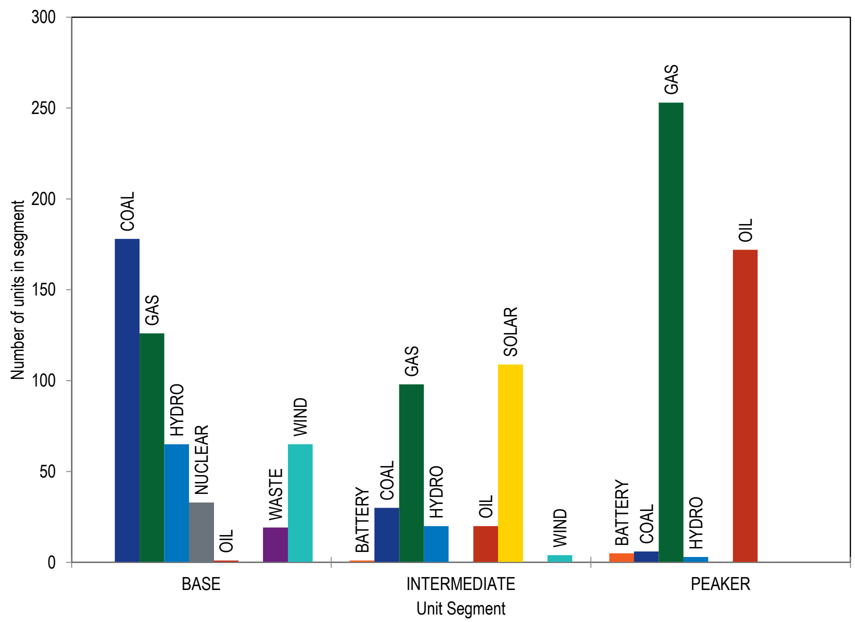
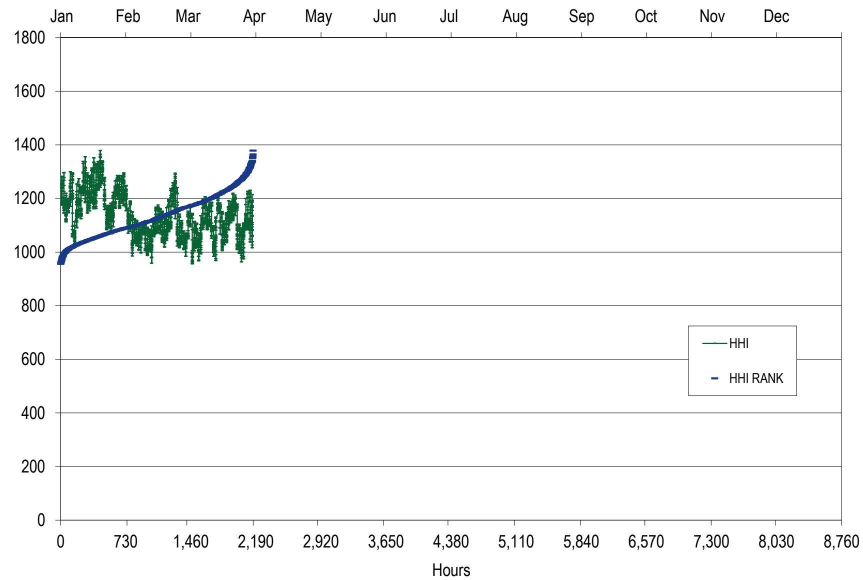


Figure 3-2 presents the hourly HHI values in chronological order and an HHI duration curve for the first three months of 2014.

Figure 3-2 PJM hourly Energy Market HHI: January through March, 2014



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 the first three months of 2014, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. The results show that in the first three months of 2014, the offers of one company contributed 19.3. percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 59.9 percent of the real-time, load-weighted, average PJM system LMP. In comparison, during the first three months of 2013, the offers of one company contributed 25.5 percent

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

of the real-time, load-weighted PJM system LMP and offers of the top four companies contributed 58.6 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): January through March 2013 and 2014

2013 (Jan-Mar)		2014 (Jan-Mar)	
Company	Percent of Price	Company	Percent of Price
1	25.5%	1	19.3%
2	11.5%	2	17.5%
3	10.9%	3	12.6%
4	10.8%	4	10.6%
5	7.6%	5	6.4%
6	5.5%	6	4.3%
7	4.2%	7	3.4%
8	3.3%	8	3.0%
9	3.3%	9	2.8%
Other (43 companies)	17.5%	Other (60 companies)	20.2%

Table 3-5 shows the contribution to PJM day-ahead, load-weighted LMP by individual marginal resource owners.[17] The contribution of each marginal resource to price at each load bus is calculated hourly and summed by company. The marginal resource owner with the largest impact on PJM day-ahead, load-weighted LMP (27.8 percent), in the first three months of 2013 also had the largest impact (7.6 percent) in the first three months of 2014.

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): January through March 2013 and 2014

2013 (Jan - Mar)		2014 (Jan - Mar)	
Company	Percent of Price	Company	Percent of Price
1	27.8%	1	7.6%
2	8.1%	2	7.4%
3	7.9%	3	6.2%
4	3.6%	4	6.2%
5	3.4%	5	5.9%
6	3.3%	6	4.4%
7	3.3%	7	4.2%
8	3.3%	8	4.0%
9	3.1%	9	3.7%
Other (114 companies)	36.1%	Other (120 companies)	50.4%

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 the first three months of 2014, coal units were 46.88 percent and natural gas units were 42.89 percent of marginal resources. In the first three months of 2013, coal units were 57.74 percent and natural gas units were 32.40 percent of the total marginal resources.

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 the first three months of 2014, 65.32 percent of the wind marginal units had negative offer prices, 33.26 percent had zero offer prices and 1.4 percent had positive offer prices.

Table 3-6 Type of fuel used (By real-time marginal units): January through March 2013 and January through March 2014

Fuel Type	2013 (Jan-Mar)	2014 (Jan-Mar)
Coal	57.74%	46.88%
Gas	32.40%	42.89%
Wind	4.76%	5.17%
Oil	4.79%	3.96%
Other	0.20%	0.76%
Uranium	0.02%	0.15%
Demand Response	0.02%	0.15%
Municipal Waste	0.07%	0.03%

Table 3-7 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first three months of 2014, up-to congestion transactions were 94.7 percent of the total marginal resources. In comparison, up-to congestion transactions were 93.5 percent of the total marginal resources in the first three months of 2013.[18]

Table 3-7 Day-ahead marginal resources by type/fuel: January through March 2013 and 2014

Type/Fuel	2013 (Jan - Mar)	2014 (Jan - Mar)
Up-to Congestion Transaction	93.54%	94.68%
Coal	2.27%	1.29%
DEC	1.71%	1.60%
INC	1.44%	1.07%
Gas	0.91%	1.05%
Dispatchable Transaction	0.09%	0.19%
Wind	0.02%	0.05%
Price Sensitive Demand	0.01%	0.02%
Municipal Waste	0.00%	0.00%
Oil	0.00%	0.01%
Diesel	0.00%	0.00%
Import	0.00%	0.03%
Total	100.00%	100.00%

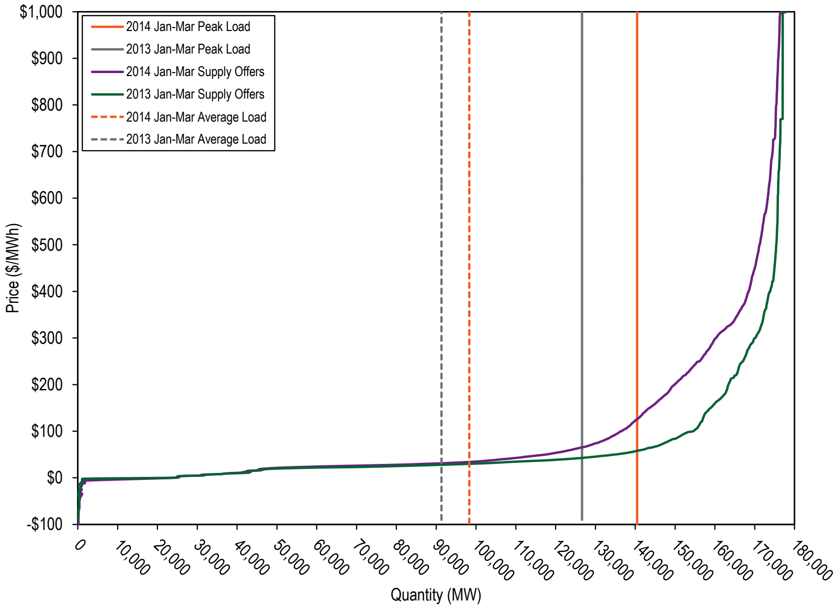
Supply

Supply includes physical generation and imports and virtual transactions.

Figure 3-3 shows the average PJM aggregate real-time generation supply curves, peak load and average load for the first three months of 2013 and the first three months of 2014.

18 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 3-3 Average PJM aggregate real-time generation supply curves: January through March of 2013 and 2014



Energy Production by Fuel Source

Compared to the first three months of 2013, generation from coal units increased 18.6 percent and generation from natural gas units increased 5.7 percent (Table 3-8).[19] Natural gas prices increased and coal prices remained relatively constant in the first three months of 2014.

Table 3-8 PJM generation (By fuel source (GWh)): January through March of 2013 and 2014[20]

	2013 (Jan-Mar)		2014 (Jan-Mar)		Change in
	GWh	Percent	GWh	Percent	Output
Coal	90,256.4	44.5%	107,029.2	48.6%	18.6%
Standard Coal	87,586.9	43.2%	104,254.9	47.4%	18.5%
Waste Coal	2,669.5	1.3%	2,774.3	1.3%	0.1%
Nuclear	72,028.7	35.5%	69,431.5	31.6%	(3.6%)
Gas	30,636.8	15.1%	32,423.4	14.7%	5.8%
Natural Gas	30,075.7	14.8%	31,789.6	14.4%	5.7%
Landfill Gas	561.1	0.3%	582.8	0.3%	3.9%
Biomass Gas	0.0	0.0%	51.0	0.0%	NA
Hydroelectric	3,576.8	1.8%	3,837.6	1.7%	7.3%
Pumped Storage	1,414.6	0.7%	1,617.6	0.7%	14.4%
Run of River	2,162.2	1.1%	2,220.0	1.0%	2.7%
Wind	4,788.1	2.4%	4,921.9	2.2%	2.8%
Waste	1,191.0	0.6%	1,177.9	0.5%	(1.1%)
Solid Waste	951.5	0.5%	936.1	0.4%	(1.6%)
Miscellaneous	239.5	0.1%	241.8	0.1%	0.9%
Oil	136.5	0.1%	1,109.3	0.5%	712.4%
Heavy Oil	105.5	0.1%	756.4	0.3%	616.8%
Light Oil	23.4	0.0%	286.5	0.1%	1,121.9%
Diesel	0.7	0.0%	48.9	0.0%	6,892.4%
Kerosene	6.9	0.0%	17.5	0.0%	155.4%
Jet Oil	0.0	0.0%	0.0	0.0%	67.9%
Solar	59.8	0.0%	67.7	0.0%	13.2%
Battery	0.1	0.0%	0.5	0.0%	277.0%
Total	202,674.2	100.0%	219,999.0	100.0%	8.5%

19 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.

20 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)): January through March of 2014

	Jan	Feb	Mar	Total
Coal	37,833.4	34,845.0	34,350.8	107,029.2
Standard Coal	36,809.3	33,985.5	33,460.1	104,254.9
Waste Coal	1,024.1	859.5	890.7	2,774.3
Nuclear	25,189.6	21,737.8	22,504.1	69,431.5
Gas	11,597.8	9,772.2	11,053.4	32,423.4
Natural Gas	11,377.6	9,566.6	10,845.4	31,789.6
Landfill Gas	207.0	181.3	194.5	582.8
Biomass Gas	13.2	24.3	13.5	51.0
Hydroelectric	1,391.3	1,074.4	1,371.9	3,837.6
Pumped Storage	536.0	530.6	551.0	1,617.6
Run of River	855.3	543.7	821.0	2,220.0
Wind	1,918.4	1,342.1	1,661.4	4,921.9
Waste	407.6	336.6	433.7	1,177.9
Solid Waste	324.2	270.0	342.0	936.1
Miscellaneous	83.4	66.6	91.7	241.8
Oil	840.7	69.2	199.3	1,109.3
Heavy Oil	585.2	39.0	132.2	756.4
Light Oil	193.4	28.7	64.4	286.5
Diesel	47.3	0.5	1.0	48.9
Kerosene	14.9	1.0	1.6	17.5
Jet Oil	0.0	0.0	0.0	0.0
Solar	16.0	20.2	31.5	67.7
Battery	0.2	0.1	0.2	0.5
Total	79,195.0	69,197.7	71,606.3	219,999.0

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 decreased by 273 MW, or 0.2 percent, from 177,820 MW in the first three months of 2013 to 177,547 MW in the first three months of 2014.[21] The decrease in offered supply was partly offset by the integration of the East Kentucky Power Cooperative (EKPC) Transmission Zone in the second quarter of 2013. In the first three months of 2014, 271 MW of new capacity were added to PJM. This new generation was mostly offset by the deactivation of four units (208 MW) since January 1, 2014. The decrease in offered supply in the first three months of 2014 was in part a result of a 1,866 MW reduction in net capacity between April 2013 and March 2014.[22]

PJM average real-time generation in the first three months of 2014, increased by 8.5 percent from the first three months of 2013, from 92,776 MW to 100,655 MW. PJM average real-time generation in the first three months of 2014 would have increased by 7.7 percent from the first three months of 2013, from 92,776 MW to 99,875 MW, if the EKPC Transmission Zone had not been included in the comparison.[23,24]

21 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.
22 The net capacity additions are calculated by taking the different between the new generation (1,036 MW) and the retired generation (2,902 MW) after April 1, 2013.
23 The EKPC Transmission Zone was integrated on June 1, 2013 and was not included in this comparison for January through March of 2013.
24 Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

PJM average real-time supply in the first three months of 2014 increased by 9.1 percent from the first three months of 2013, from 98,002 MW to 106,879 MW. PJM average real-time supply in the first three months of 2014 would have increased by 8.3 percent from the first three months of 2013, from 98,002 MW to 106,098 MW, if the EKPC Transmission Zone had not been included in the comparison.

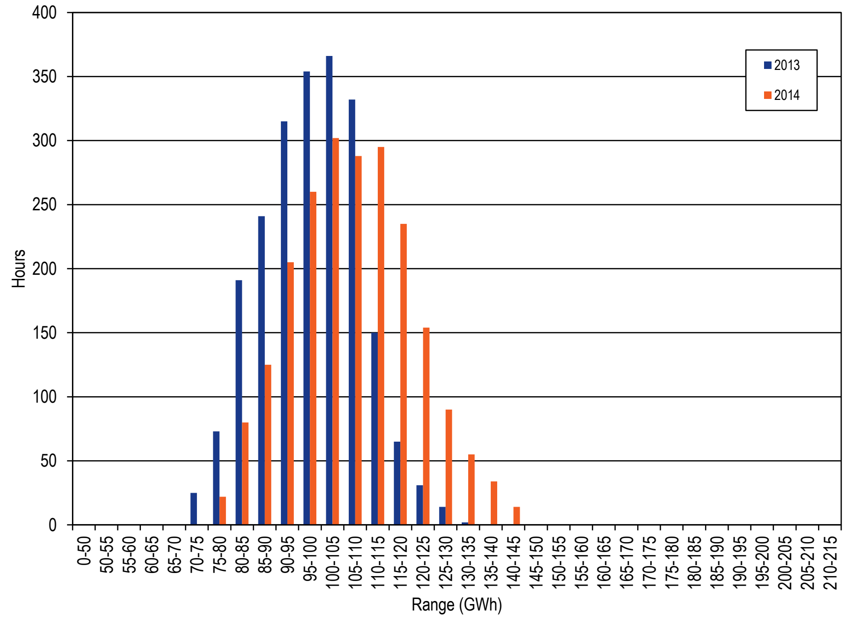
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **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 3-4 shows the hourly distribution of PJM real-time generation plus imports for the first three months of 2013 and the first three months of 2014.

Figure 3-4 Distribution of PJM real-time generation plus imports: January through March of 2013 and 2014[25]



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 first three months of the 15-year period from 2000 through 2014.[26]

Table 3-10 PJM real-time average hourly generation and real-time average hourly generation plus average hourly imports: January through March of 2000 through 2014

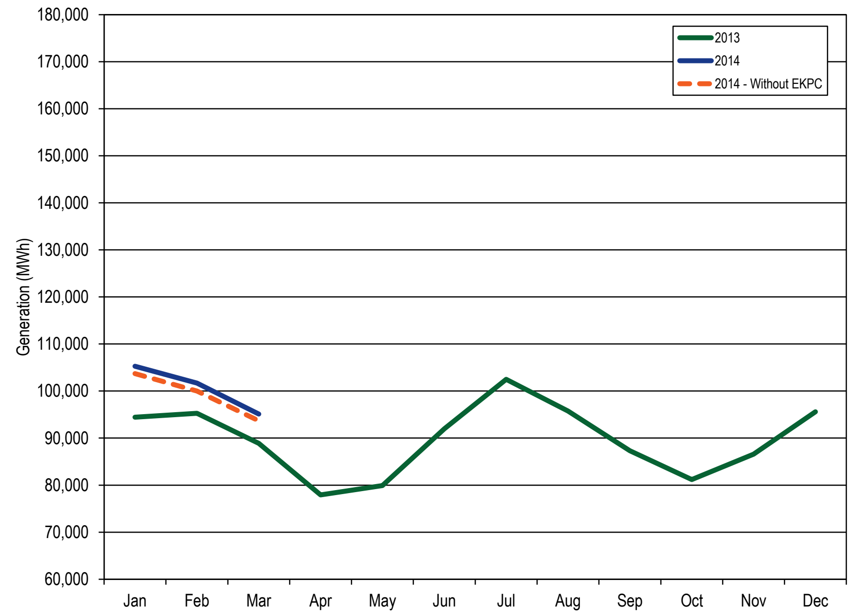
	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
Jan-Mar	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2000	NA	NA	NA	NA	NA	NA	NA	NA
2001	30,923	3,488	33,806	3,358	NA	NA	NA	NA
2002	27,948	3,416	31,465	3,508	(9.6%)	(2.1%)	(6.9%)	4.5%
2003	38,731	5,187	42,498	5,092	38.6%	51.8%	35.1%	45.1%
2004	37,790	4,660	41,960	4,899	(2.4%)	(10.2%)	(1.3%)	(3.8%)
2005	74,187	8,269	80,184	9,017	96.3%	77.4%	91.1%	84.1%
2006	82,550	7,921	87,729	8,565	11.3%	(4.2%)	9.4%	(5.0%)
2007	86,286	10,018	91,454	11,351	4.5%	26.5%	4.2%	32.5%
2008	86,690	9,375	92,075	10,150	0.5%	(6.4%)	0.7%	(10.6%)
2009	81,987	11,417	88,148	12,213	(5.4%)	21.8%	(4.3%)	20.3%
2010	81,676	12,801	87,009	13,236	(0.4%)	12.1%	(1.3%)	8.4%
2011	83,505	10,116	88,750	10,884	2.2%	(21.0%)	2.0%	(17.8%)
2012	88,068	11,177	93,128	11,685	5.5%	10.5%	4.9%	7.4%
2013	92,776	10,030	98,002	10,812	5.3%	(10.3%)	5.2%	(7.5%)
2014	100,655	12,427	106,879	13,255	8.5%	23.9%	9.1%	22.6%

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.

PJM Real-Time, Monthly Average Generation

Figure 3-5 compares the real-time, monthly average hourly generation in 2013 to the first three months of 2014 with and without EKPC.

Figure 3-5 PJM real-time average monthly hourly generation: January 2013 through March 2014



Day-Ahead Supply

PJM average day-ahead supply in the first three months of 2014, including INCs and up-to congestion transactions, increased by 14.3 percent from the first three months of 2013, from 147,246MW to 168,373 MW. The PJM average day-ahead supply in the first three months of 2014, including INCs and up-to congestion transactions, would have increased by 13.7 percent in the first three months of 2014, from 147,246 MW to 167,394 MW, if the EKPC Transmission Zone had not been included in the comparison.

PJM average day-ahead supply in the first three months of 2014, including INCs, up-to congestion transactions, and imports, increased by 14.4 percent from the first three months of 2013, from 149,300 MW to 170,778 MW. PJM average day-ahead supply in the first three months of 2014, including INCs, up-to congestion transactions, and imports, would have increased by 13.7 percent from the first three months of 2013, from 149,300 MW to 169,799 MW, if the EKPC Transmission Zone had not been included in the comparison.

The day-ahead supply growth was 68.2 percent higher than the real-time generation growth in the first three months of 2014, because of the continued growth of up-to congestion transactions. If the first three months of 2014 up-to congestion transactions had been held to the first three months of 2013 levels, the day-ahead supply, including INCs and up-to congestion transactions, would have increased 4.1 percent instead of 14.3 percent and day-ahead supply growth would have been 51.8 percent lower than the real-time generation growth.

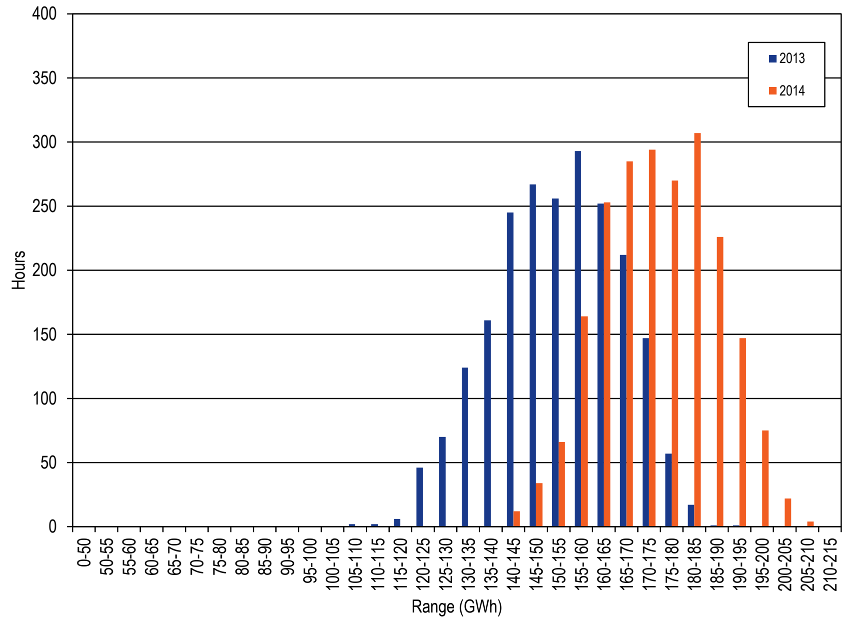
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **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 3-6 shows the hourly distribution of PJM day-ahead supply, including increment offers, up-to congestion transactions, and imports for the first three months of 2013 and the first three months of 2014.

Figure 3-6 Distribution of PJM day-ahead supply plus imports: January through March of 2013 and 2014[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 the first three months of each year of the 15-year period from 2000 through 2014.[28]

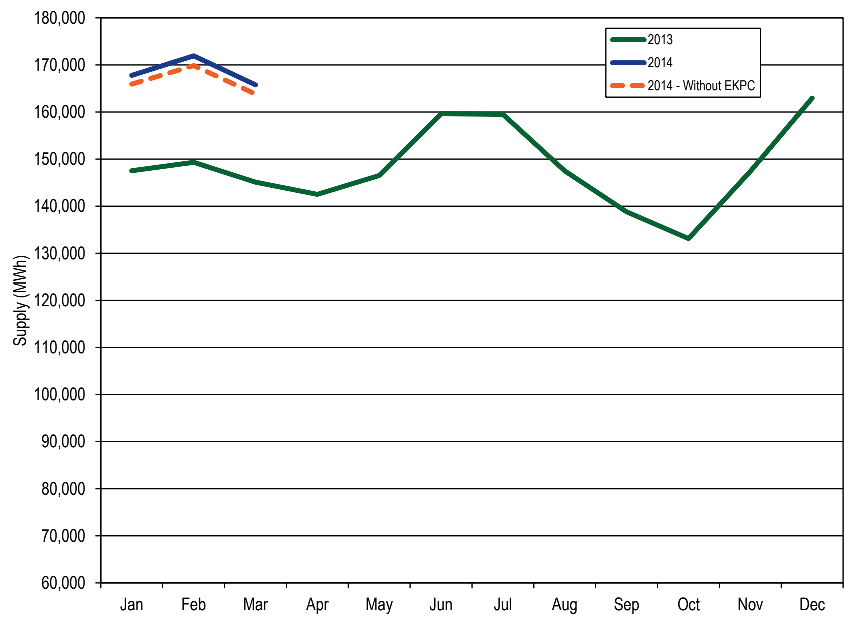
Table 3-11 PJM day-ahead average hourly supply and day-ahead average hourly supply plus average hourly imports: January through March of 2000 through 2014

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
Jan-Mar	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2000	NA	NA	NA	NA	NA	NA	NA	NA
2001	28,494	2,941	29,252	3,021	NA	NA	NA	NA
2002	20,274	10,131	20,827	10,134	(28.8%)	244.5%	(28.8%)	235.5%
2003	37,147	4,337	37,807	4,389	83.2%	(57.2%)	81.5%	(56.7%)
2004	46,591	4,794	47,377	5,039	25.4%	10.5%	25.3%	14.8%
2005	89,011	9,434	90,502	9,443	91.0%	96.8%	91.0%	87.4%
2006	97,319	9,035	99,551	9,061	9.3%	(4.2%)	10.0%	(4.0%)
2007	110,099	11,938	112,561	12,141	13.1%	32.1%	13.1%	34.0%
2008	109,711	10,479	112,165	10,671	(0.4%)	(12.2%)	(0.4%)	(12.1%)
2009	104,880	13,895	107,325	14,031	(4.4%)	32.6%	(4.3%)	31.5%
2010	101,733	13,835	104,858	13,917	(3.0%)	(0.4%)	(2.3%)	(0.8%)
2011	110,310	12,200	112,854	12,419	8.4%	(11.8%)	7.6%	(10.8%)
2012	132,178	13,701	134,405	13,804	19.8%	12.3%	19.1%	11.2%
2013	147,246	13,054	149,300	13,244	11.4%	(4.7%)	11.1%	(4.1%)
2014	168,373	11,875	170,778	11,935	14.3%	(9.0%)	14.4%	(9.9%)

PJM Day-Ahead, Monthly Average Supply

Figure 3-7 compares the day-ahead, monthly average hourly supply, including increment offers and up-to congestion transactions, in 2013 to the first three months of 2014 with and without EKPC.

Figure 3-7 PJM day-ahead monthly average hourly supply: January 2013 through March 2014



Real-Time and Day-Ahead Supply

Table 3-12 presents summary statistics for the first three months of 2013 and the first three months of 2014 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-

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.

ahead generation less the total physical real-time generation. In the first three months of 2014, up-to congestion transactions were 36.2 percent of the total day-ahead supply compared to 31.3 percent in the first three months of 2013.

Table 3-12 Day-ahead and real-time supply (MWh): January through March of 2013 and 2014

		Day Ahead					Real Time		Day Ahead Less Real Time	
	Jan-Mar	Generation	INC Offers	Up-to Congestion	Imports	Total Supply	Generation	Total Supply	Total Supply	Total Generation
Average	2013	94,829	5,673	46,745	2,054	149,300	92,776	98,002	51,298	2,053
	2014	103,436	3,036	61,900	2,405	170,778	100,655	106,879	63,899	2,781
Median	2013	95,320	5,702	46,492	2,006	150,072	93,346	98,551	51,521	1,974
	2014	103,052	2,990	62,016	2,389	170,973	100,441	106,441	64,532	2,611
Standard Deviation	2013	10,944	680	8,831	325	13,244	10,030	10,812	2,432	913
	2014	13,013	583	9,194	332	11,935	12,427	13,255	(1,320)	586
Peak Average	2013	102,331	6,085	46,276	2,196	156,888	99,495	105,263	51,625	2,835
	2014	111,437	3,319	61,213	2,465	178,433	107,919	114,609	63,824	3,517
Peak Median	2013	101,557	6,096	46,487	2,213	157,676	99,374	105,002	52,674	2,183
	2014	111,097	3,303	61,595	2,438	178,947	107,578	114,098	64,849	3,519
Peak Standard Deviation	2013	7,445	508	7,734	305	9,892	7,131	7,757	2,136	313
	2014	10,549	558	8,848	290	9,079	10,139	10,874	(1,795)	410
Off-Peak Average	2013	88,258	5,313	47,155	1,929	142,655	86,891	91,643	51,012	1,368
	2014	96,430	2,789	62,502	2,353	164,074	94,294	100,108	63,966	2,137
Off-Peak Median	2013	87,617	5,210	46,492	1,869	142,311	86,261	90,775	51,536	1,356
	2014	95,708	2,776	62,255	2,352	163,372	93,428	99,080	64,292	2,279
Off-Peak Standard Deviation	2013	9,147	602	9,675	288	12,198	8,367	8,944	3,254	780
	2014	10,728	484	9,449	357	9,938	10,631	11,308	(1,370)	98

Figure 3-8 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 3-8 Day-ahead and real-time supply (Average hourly volumes): January through March of 2014

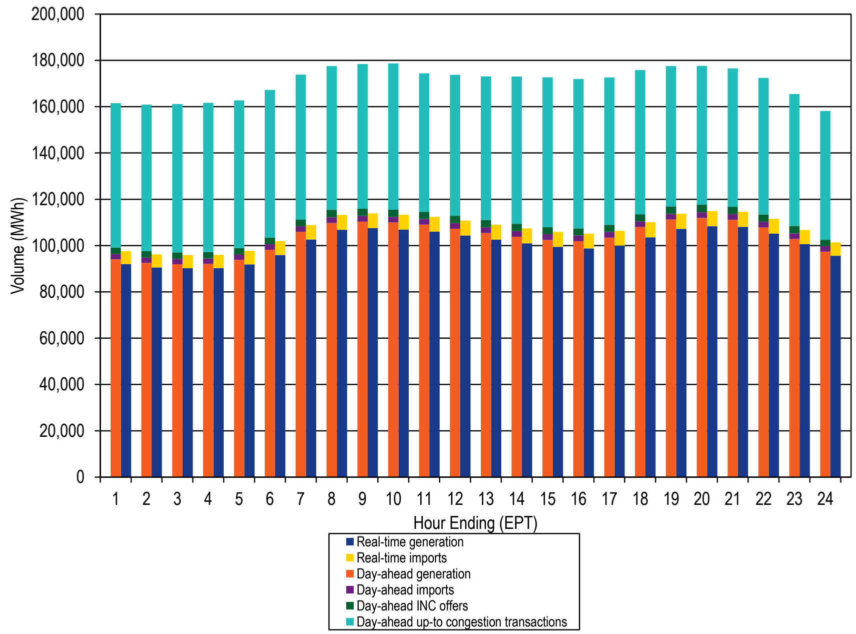


Figure 3-9 shows the difference between the day-ahead and real-time average daily supply in January 2013 through March of 2014.

Figure 3-9 Difference between day-ahead and real-time supply (Average daily volumes): January 2013 through March of 2014

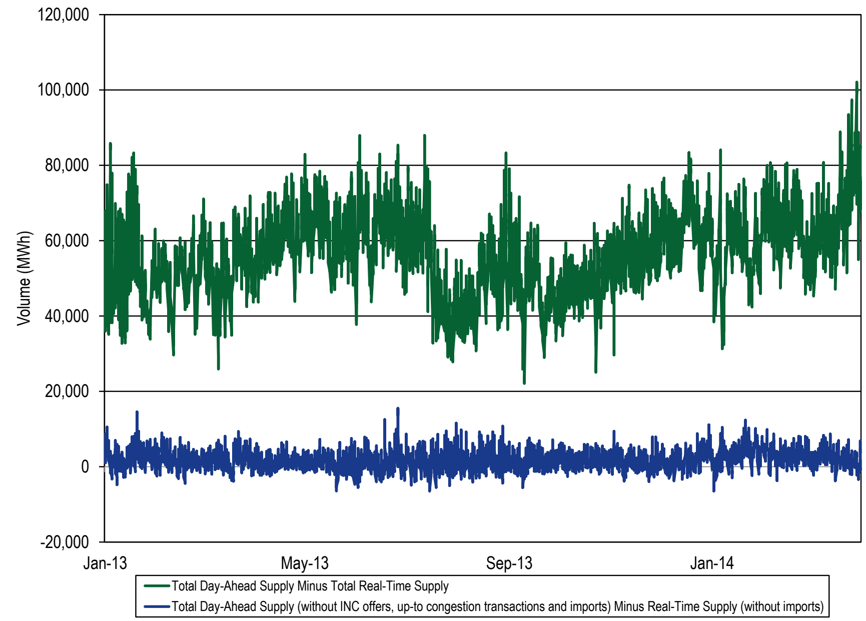
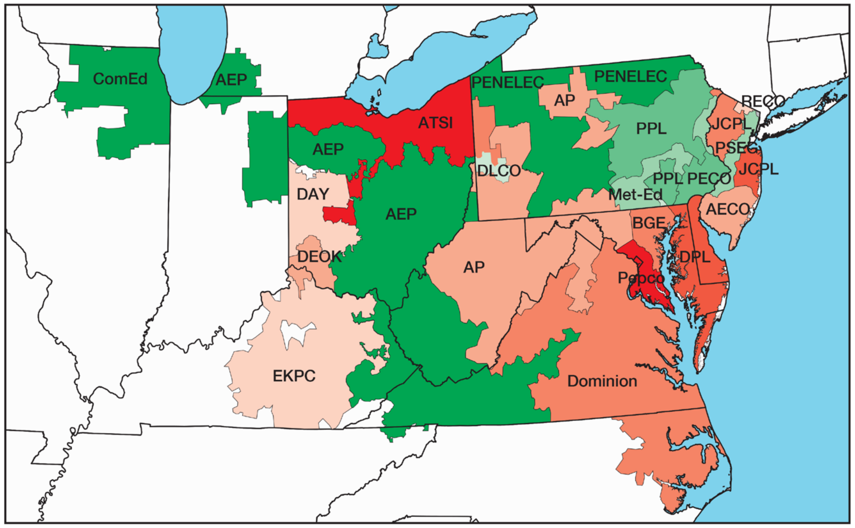


Figure 3-10 shows the difference between the PJM real-time generation and real-time load by zone in the first three months of 2014. Table 3-13 shows the difference between the PJM real-time generation and real-time load by zone in the first three months of 2013 and the first three months of 2014. Figure 3-10 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 3-10 Map of PJM real-time generation less real-time load by zone: January through March of 2014[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	(1,676)	ComEd	7,133	DPL	(3,396)	PENELEC	8,105
AEP	8,039	DAY	(525)	EKPC	(519)	Pepco	(4,299)
AP	(1,452)	DEOK	(1,366)	JCPL	(3,379)	PPL	2,786
ATSI	(4,141)	DLCO	565	Met-Ed	1,199	PSEG	1,441
BGE	(3,014)	Dominion	(3,136)	PECO	3,041	RECO	(358)

Table 3-13 PJM real-time generation less real-time load by zone (GWh): January through March of 2013 and 2014

	Zonal Generation and Load (GWh)					
	2013 (Jan-Mar)			2014 (Jan-Mar)		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	400.5	2,472.5	(2,072.0)	901.5	2,577.5	(1,676.0)
AEP	35,431.1	34,699.0	732.1	43,861.2	35,822.5	8,038.6
AP	14,090.8	12,833.1	1,257.7	12,269.3	13,721.3	(1,452.0)
ATSI	14,092.2	17,074.0	(2,981.8)	14,064.9	18,205.7	(4,140.8)
BGE	4,826.2	8,298.0	(3,471.8)	5,872.2	8,886.4	(3,014.3)
ComEd	31,380.5	24,356.2	7,024.2	32,743.1	25,609.6	7,133.5
DAY	4,026.8	4,317.1	(290.3)	4,090.6	4,615.5	(524.9)
DEOK	6,615.6	6,730.9	(115.2)	5,796.0	7,161.7	(1,365.7)
DLCO	4,841.3	3,638.3	1,203.0	4,377.8	3,813.0	564.8
Dominion	20,993.3	24,333.0	(3,339.7)	23,017.3	26,153.4	(3,136.1)
DPL	1,602.2	4,838.0	(3,235.8)	1,762.0	5,157.8	(3,395.7)
EKPC	NA	NA	NA	3,370.4	3,889.2	(518.9)
JCPL	1,881.6	5,527.1	(3,645.6)	2,453.7	5,833.2	(3,379.5)
Met-Ed	5,427.8	3,956.2	1,471.6	5,404.0	4,205.4	1,198.6
PECO	15,004.3	10,069.0	4,935.3	13,664.3	10,623.3	3,041.1
PENELEC	11,825.4	4,637.0	7,188.4	12,914.7	4,809.2	8,105.5
Pepco	2,161.9	7,625.7	(5,463.8)	3,924.5	8,223.8	(4,299.3)
PPL	13,815.7	10,996.3	2,819.4	14,584.9	11,798.4	2,786.5
PSEG	11,885.4	10,440.5	1,444.9	12,242.3	10,801.5	1,440.8
RECO	0.0	353.8	(353.8)	0.0	358.4	(358.4)

Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

The PJM system load reflects 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 physical load and exports and in the Day-Ahead Energy Market also includes virtual transactions, which include decrement bids and up-to congestion transactions.

The PJM system real-time peak load for the first three months of 2014 was 140,467 MW in the HE 1900 on January 7, 2014, which was 13,835 MW, or 10.9 percent, higher than the PJM peak load for the first three months of

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>. (Accessed on 4/14/2014.)

2013, which was 126,632 MW in the HE 1900 on January 22, 2013. The EKPC Transmission Zone accounted for 2,842 MW in the peak hour of the first three months of 2014. The peak load excluding the EKPC Transmission Zone was 137,625 MW, also occurring on January 7, 2014, HE 1900, an increase of 10,993 MW, or 8.7 percent from the first three months of 2013.

Table 3-14 shows the coincident peak loads for January through March of the years 1999 through 2014.

Table 3-14 Actual PJM footprint peak loads: January through March of 1999 to 2014[30]

(Jan - Mar)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Tue, January 05	19	99,982	NA	NA
2000	Thu, January 27	20	102,359	2,377	2.4%
2001	Tue, January 02	19	100,411	(1,948)	(1.9%)
2002	Mon, March 04	20	97,334	(3,077)	(3.1%)
2003	Thu, January 23	19	112,755	15,421	15.8%
2004	Mon, January 26	19	106,760	(5,995)	(5.3%)
2005	Tue, January 18	19	111,973	5,213	4.9%
2006	Mon, February 13	20	100,065	(11,908)	(10.6%)
2007	Mon, February 05	20	118,800	18,736	18.7%
2008	Thu, January 03	19	111,724	(7,076)	(6.0%)
2009	Fri, January 16	19	117,169	5,445	4.9%
2010	Mon, January 04	19	109,210	(7,959)	(6.8%)
2011	Mon, January 24	8	110,659	1,448	1.3%
2012	Tue, January 03	19	122,539	11,880	10.7%
2013	Tue, January 22	19	126,632	4,093	3.3%
2014 (with EKPC)	Tue, January 07	19	140,467	13,835	10.9%
2014 (without EKPC)	Tue, January 07	19	137,625	10,993	8.7%

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>.

Figure 3-11 shows the peak loads for the first three months of the years 1999 through 2014.

Figure 3-11 PJM footprint calendar year peak loads: January through March of 1999 to 2014

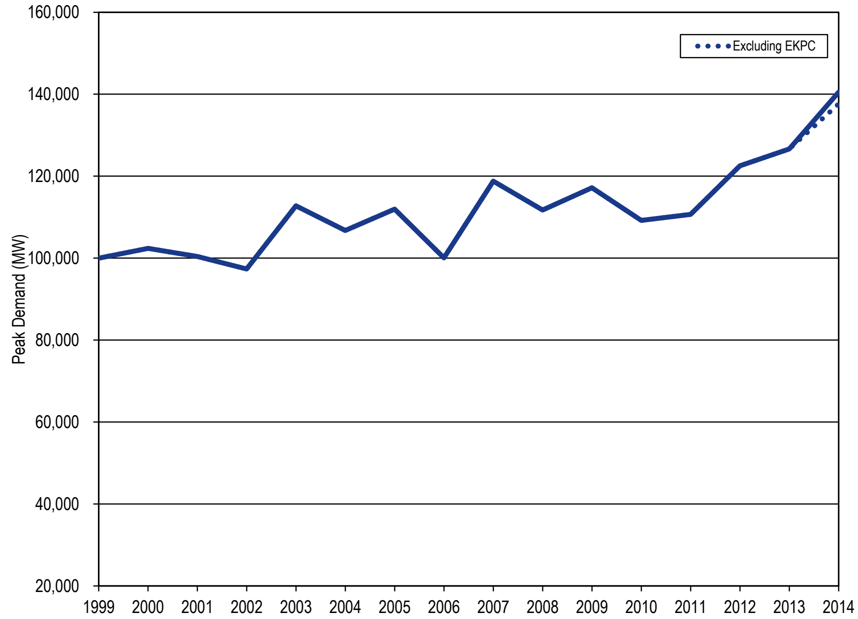
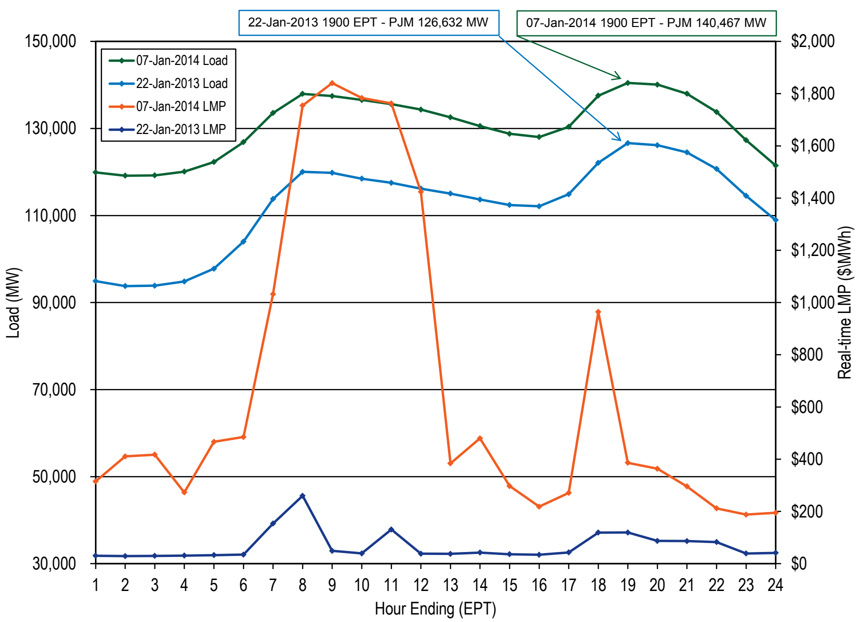


Figure 3-12 compares the peak load days in the first three months of 2013 and the first three months of 2014. In every hour on January 7, 2014, the average hourly real-time load and LMP was higher than the average hourly real-time load and LMP on January 22, 2013. The average hourly real-time LMP peaked at $1,840.54 on January 7, 2014 and peaked at $259.80 on January 22, 2013. The high LMPs on January 7, 2014, were caused by high demand combined with high forced outage rates and uncertainty in gas supply, which resulted in shortage pricing from hour ending 0800 through hour ending 1300. On January 7, demand response was marginal from hour ending 0700 through hour ending 1200 and hour ending 1800. The peak hourly real-time LMP was greater than $1,800 per MWh. Following the implementation of shortage pricing, generator offers remained capped at $1,000 per MWh but demand response offers were capped at $1,800 for the period between June 1, 2013, and May 31, 2014. The $1,800 is equal to the generator offer cap plus the sum of the applicable penalty factors ($800 per MWh) for synchronized reserves and non-synchronized primary reserves. This means that the highest possible SMP is $1,800 in the period between June 1, 2013, and May 31, 2014 unless there are emergency purchases on the margins with higher prices. SMP did exceed $1,800 per MWh in some intervals in which there were no emergency purchases. This suggests that the prices in excess of $1,800 per MWh on January 7, 2014, were a result of the way in which PJM modeled zonal (not nodal) demand response as a marginal resource.

Figure 3-12 PJM peak-load comparison: Tuesday, January 7, 2014, and Tuesday, January 22, 2013



Real-Time Demand

PJM average real-time load in the first three months of 2014 increased by 7.6 percent from the first three months of 2013, from 91,337 MW to 98,317 MW. The PJM average real-time load in the first three months of 2014 would have increased by 6.7 percent from the first three months of 2013, from 91,337 MW to 97,417 MW, if the EKPC Transmission Zone had not been included in the comparison.[31,32]

PJM average real-time demand in the first three months of 2014 increased 9.0 percent from the first three months of 2013, from 95,835 MW to 104,454 MW. The PJM average real-time demand in the first three months of 2014 would have increased by 8.1 percent from the first three months of 2013, from 95,835 MW to 103,553 MW, if the EKPC Transmission Zone had not been included in the comparison.

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

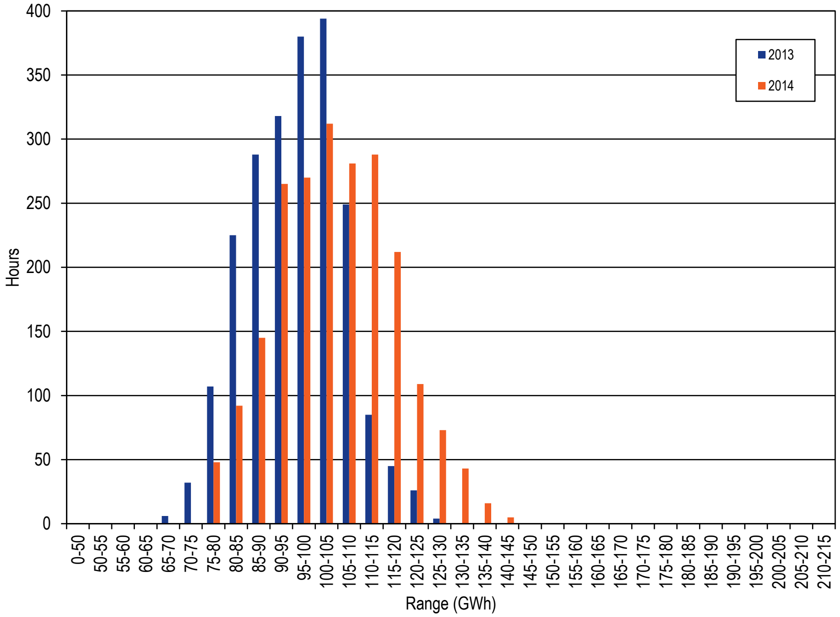
- **Load.** The actual MWh level of energy used.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. A real-time export must have a valid OASIS reservation when offered, must have available ramp room to support the export, must be accompanied by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

PJM Real-Time Demand Duration

Figure 3-13 shows the hourly distribution of PJM real-time load plus exports for the first three months of 2013 and the first three months of 2014.[33]

31 The EKPC Transmission Zone was integrated on June 1, 2013 and was not included in this comparison for January through March 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 3-13 Distribution of PJM real-time accounting load plus exports: January through March of 2013 and 2014[34]



PJM Real-Time, Average Load

Table 3-15 presents summary real-time demand statistics for the first three months of each year during the 17-year period 1998 to 2014. 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.[35]

Table 3-15 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: January through March of 1998 through 2014[36,37]

	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Jan-Mar	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
1998	28,019	3,762	NA	NA	NA	NA	NA	NA
1999	29,784	4,027	NA	NA	6.3%	7.0%	NA	NA
2000	30,367	4,624	30,367	4,624	2.0%	14.8%	NA	NA
2001	31,254	3,846	33,452	3,704	2.9%	(16.8%)	10.2%	(19.9%)
2002	29,968	4,083	30,988	3,932	(4.1%)	6.1%	(7.4%)	6.1%
2003	39,249	5,546	41,600	5,701	31.0%	35.8%	34.2%	45.0%
2004	39,549	5,761	41,198	5,394	0.8%	3.9%	(1.0%)	(5.4%)
2005	71,388	8,966	79,319	9,587	80.5%	55.6%	92.5%	77.8%
2006	80,179	8,977	86,568	9,378	12.3%	0.1%	9.1%	(2.2%)
2007	84,586	12,040	90,304	12,012	5.5%	34.1%	4.3%	28.1%
2008	82,235	10,184	89,092	10,621	(2.8%)	(15.4%)	(1.3%)	(11.6%)
2009	81,170	11,718	86,110	11,948	(1.3%)	15.1%	(3.3%)	12.5%
2010	81,121	10,694	86,843	11,262	(0.1%)	(8.7%)	0.9%	(5.7%)
2011	81,018	10,273	86,635	10,613	(0.1%)	(3.9%)	(0.2%)	(5.8%)
2012	86,329	10,951	91,090	11,293	6.6%	6.6%	5.1%	6.4%
2013	91,337	10,610	95,835	10,452	5.8%	(3.1%)	5.2%	(7.4%)
2014	98,317	13,484	104,454	12,843	7.6%	27.1%	9.0%	22.9%

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

35 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.

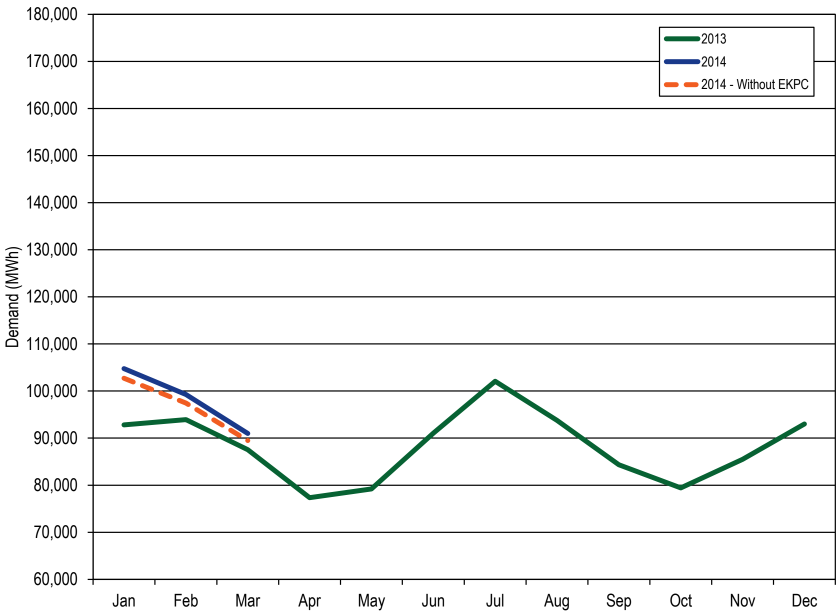
36 The data used in the version of this table in the *2012 State of the Market Report for PJM* have been updated by PJM and the updates are reflected in this table.

37 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.

PJM Real-Time, Monthly Average Load

Figure 3-14 compares the real-time, monthly average hourly loads in 2013 to the first three months of 2014 with and without EKPC.

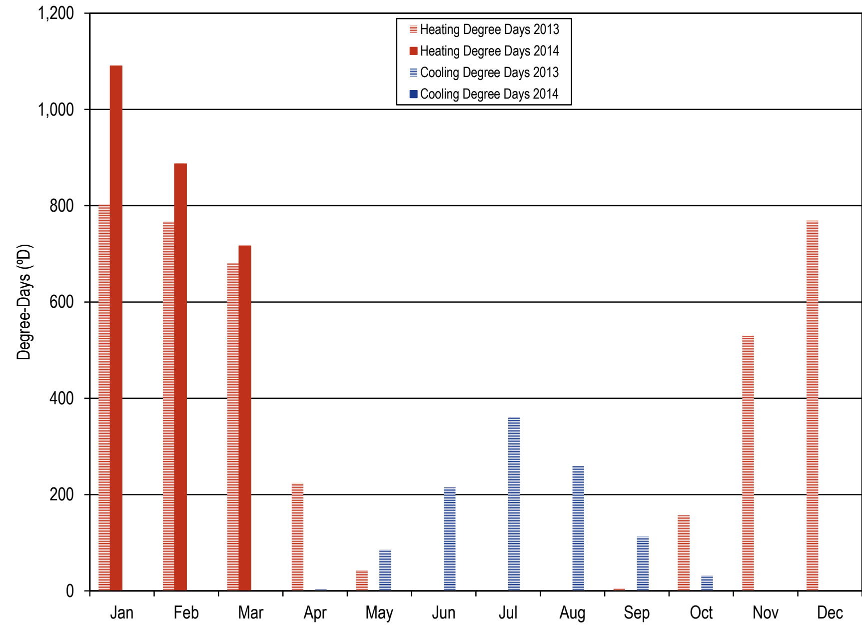
Figure 3-14 PJM real-time monthly average hourly load: January 2013 through March 2014



PJM real-time load is significantly affected by temperature. Figure 3-15 compares the total PJM monthly heating and cooling degree days in the first three months of 2014 with those in 2013.[38] The figure shows that in 2014, the heating degree days increased 35.8 percent in January, 15.6 percent in February, and 5.2 percent in March compared to 2013.

38 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, LEX, ORD, ORF, PHL, PIT, RIC, ROA, TOL and WAL.

Figure 3-15 PJM heating and cooling degree days: January 2013 through March 2014



Day-Ahead Demand

PJM average day-ahead demand in the first three months of 2014, including DECs and up-to congestion transactions, increased by 13.5 percent from the first three months of 2013, from 143,585 MW to 163,031 MW. The PJM average day-ahead demand in the first three months of 2014, including DECs and up-to congestion transactions, would have increased 12.8 percent from the first three months of 2013, from 143,585 MW to 161,982 MW, if the EKPC Transmission Zone had not been included in the comparison.

PJM average day-ahead demand in the first three months of 2014, including DECs, up-to congestion transactions, and exports, increased by 13.9 percent from the first three months of 2013, from 146,878 MW to 167,318 MW. The PJM average day-ahead demand in the first three months of 2014, including

DECs and up-to congestion transactions, and imports, would have increased 13.2 percent from the first three months of 2013, from 146,878 MW to 166,269 MW, if the EKPC Transmission Zone had not been included in the comparison.

The day-ahead demand growth was 77.6 percent higher than the real-time load growth in the first three months of 2014, because of the continued growth of up-to congestion transactions. If the first three months of 2014 up-to congestion transactions had been held to the first three months of 2013 levels, the day-ahead demand, including DECs and up-to congestion transactions, would have increased 3.0 percent instead of increasing 13.5 percent and day-ahead demand growth would have been 60.7 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:

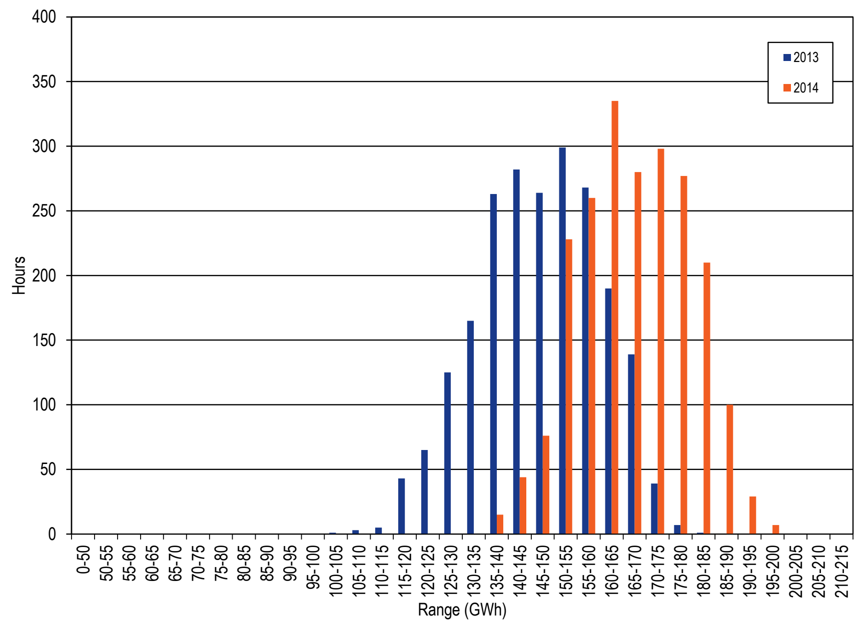
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of 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 3-16 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up-to congestion transactions, and exports for the first three months of 2013 and the first three months of 2014.

Figure 3-16 Distribution of PJM day-ahead demand plus exports: January through March of 2013 and 2014[39]



39 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 the first three months of each year of the 15-year period 2000 to 2014.[40]

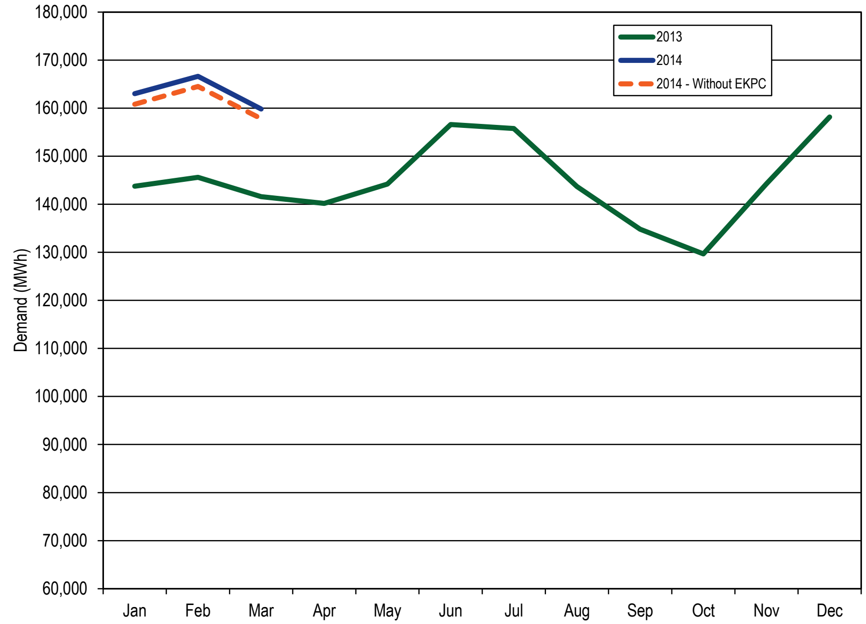
Table 3-16 PJM day-ahead average demand and day-ahead average hourly demand plus average hourly exports: January through March of 2000 through 2014

	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
Jan-Mar	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2000	NA	NA	NA	NA	NA	NA	NA	NA
2001	33,731	4,557	34,523	4,390	NA	NA	NA	NA
2002	33,976	4,960	34,004	4,964	0.7%	8.9%	(1.5%)	13.1%
2003	47,034	6,841	47,147	6,853	38.4%	37.9%	38.7%	38.1%
2004	46,885	5,591	47,123	5,537	(0.3%)	(18.3%)	(0.1%)	(19.2%)
2005	87,341	9,810	90,288	9,947	86.3%	75.5%	91.6%	79.7%
2006	96,244	9,453	99,342	9,777	10.2%	(3.6%)	10.0%	(1.7%)
2007	108,699	12,601	111,831	12,746	12.9%	33.3%	12.6%	30.4%
2008	105,995	10,677	109,428	10,975	(2.5%)	(15.3%)	(2.1%)	(13.9%)
2009	102,366	13,619	105,023	13,758	(3.4%)	27.5%	(4.0%)	25.4%
2010	101,012	11,937	104,866	12,103	(1.3%)	(12.4%)	(0.1%)	(12.0%)
2011	107,116	11,890	110,865	12,157	6.0%	(0.4%)	5.7%	0.4%
2012	129,258	13,163	132,757	13,481	20.7%	10.7%	19.7%	10.9%
2013	143,585	13,120	146,878	13,108	11.1%	(0.3%)	10.6%	(2.8%)
2014	163,031	11,914	167,318	11,717	13.5%	(9.2%)	13.9%	(10.6%)

PJM Day-Ahead, Monthly Average Demand

Figure 3-17 compares the day-ahead, monthly average hourly demand, including decrement bids and up-to congestion transactions, in 2013 to the first three months of 2014 with and without EKPC.

Figure 3-17 PJM day-ahead monthly average hourly demand: January 2013 through March 2014



Real-Time and Day-Ahead Demand

Table 3-17 presents summary statistics for the first three months of 2013 and the first three months of 2014 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.

40 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 3-17 Cleared day-ahead and real-time demand (MWh): January through March of 2013 and 2014

		Day Ahead						Real Time		Day Ahead Less Real Time	
	Jan-Mar	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Total Demand	Total Load
Average	2013	88,395	943	7,502	46,745	3,293	146,878	91,337	95,835	51,043	(1,998)
	2014	93,636	1,313	6,182	61,900	4,287	167,318	98,317	104,454	62,865	(3,368)
Median	2013	89,132	873	7,188	46,492	3,205	147,579	91,993	96,405	51,174	(1,988)
	2014	93,237	1,299	6,034	62,016	4,293	167,410	97,634	104,102	63,308	(3,098)
Standard Deviation	2013	9,989	223	1,550	8,831	458	13,108	10,610	10,452	2,656	(398)
	2014	13,129	178	1,038	9,194	1,047	11,717	13,484	12,843	(1,126)	(177)
Peak Average	2013	95,586	1,004	8,190	46,276	3,303	154,360	98,579	102,910	51,450	(1,989)
	2014	101,478	1,377	6,476	61,213	4,257	174,801	105,895	111,985	62,816	(3,040)
Peak Median	2013	95,116	857	7,760	46,487	3,209	155,261	98,355	102,687	52,575	(2,382)
	2014	100,970	1,381	6,442	61,595	4,208	175,209	105,385	111,466	63,743	(3,034)
Peak Standard Deviation	2013	6,484	237	1,514	7,734	468	9,854	7,400	7,436	2,418	(679)
	2014	11,041	178	916	8,848	1,068	8,994	11,407	10,539	(1,546)	(187)
Off-Peak Average	2013	82,098	889	6,899	47,155	3,285	140,326	84,994	89,639	50,687	(2,006)
	2014	86,769	1,256	5,924	62,502	4,314	160,766	91,681	97,859	62,907	(3,656)
Off-Peak Median	2013	81,676	882	6,556	46,492	3,199	140,055	84,250	88,843	51,212	(1,693)
	2014	85,826	1,235	5,690	62,255	4,392	160,161	90,347	96,837	63,324	(3,286)
Off-Peak Standard Deviation	2013	8,087	195	1,311	9,675	448	12,056	8,777	8,618	3,438	(496)
	2014	10,752	158	1,070	9,449	1,028	9,734	11,525	10,908	(1,174)	(616)

Figure 3-18 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 day-ahead demand includes day-ahead load and day-ahead exports.

Figure 3-18 Day-ahead and real-time demand (Average hourly volumes): January through March of 2014

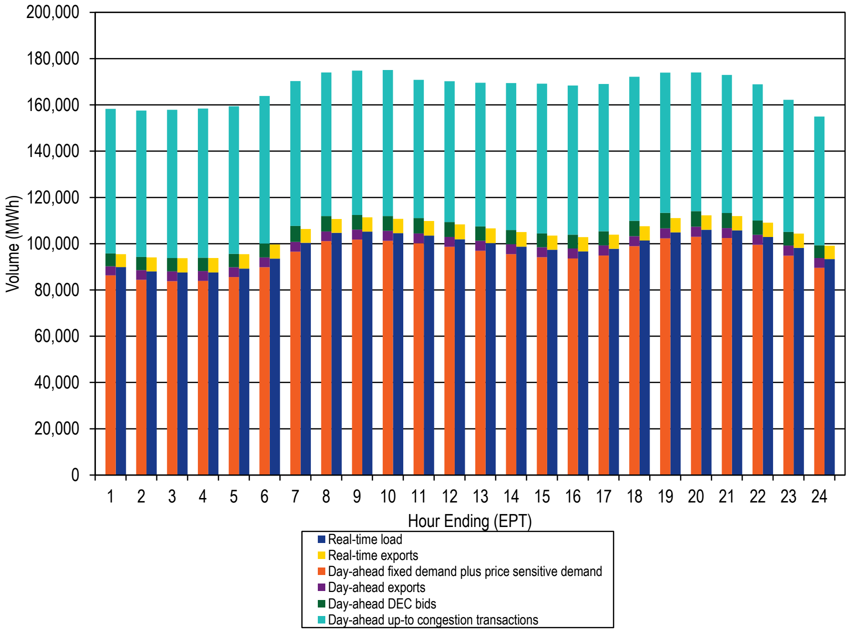
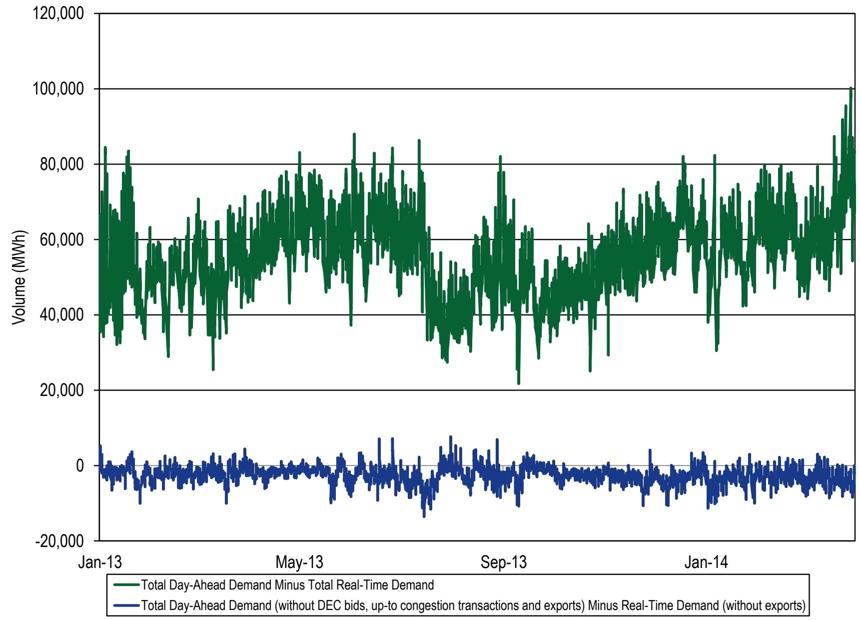


Figure 3-19 shows the difference between the day-ahead and real-time average daily demand in January 2013 through March 2014.

Figure 3-19 Difference between day-ahead and real-time demand (Average daily volumes): January 2013 through March 2014



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 2013 and 2014 based on parent company. For the first three months of 2014, 9.5 percent of real-time load was supplied by bilateral contracts, 27.5 percent by spot market purchase and 63.0 percent by self-supply. Compared with 2013, reliance on bilateral contracts decreased 1.1 percentage points, reliance on spot supply increased by 2.5 percentage points and reliance on self-supply decreased by 1.4 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: 2013 through 2014

	2013			2014			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	10.4%	22.3%	67.3%	9.5%	27.9%	62.6%	(0.9%)	5.7%	(4.7%)
Feb	10.5%	22.0%	67.5%	9.2%	27.3%	63.5%	(1.4%)	5.3%	(4.0%)
Mar	10.4%	24.2%	65.4%	9.7%	27.2%	63.0%	(0.7%)	3.1%	(2.4%)
Apr	10.7%	24.2%	65.1%						
May	10.9%	25.4%	63.6%						
Jun	10.7%	25.0%	64.3%						
Jul	10.2%	25.2%	64.7%						
Aug	10.2%	24.5%	65.3%						
Sep	10.1%	24.2%	65.7%						
Oct	11.1%	28.2%	60.7%						
Nov	10.6%	27.2%	62.2%						
Dec	11.3%	27.1%	61.7%						
Annual	10.6%	25.0%	64.4%	9.5%	27.5%	63.0%	(1.1%)	2.5%	(1.4%)

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.

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 2013 and 2014, based on parent companies. For the first three months of 2014, 9.2 percent of day-ahead demand was supplied by bilateral contracts, 27.9 percent by spot market purchases, and 62.9 percent by self-supply. Compared with 2013, reliance on bilateral contracts increased by 1.2

percentage points, reliance on spot supply increased by 3.4 percentage points, and reliance on self-supply decreased by 4.6 percentage points.

Table 3-19 Monthly average percentage of day-ahead self-supply demand, bilateral supply demand, and spot-supply demand based on parent companies: 2013 through 2014

	2013			2014			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	6.8%	22.1%	71.1%	10.9%	28.7%	60.4%	4.1%	6.7%	(10.7%)
Feb	7.0%	22.1%	71.0%	7.9%	27.0%	65.0%	1.0%	5.0%	(5.9%)
Mar	7.0%	23.6%	69.4%	8.6%	27.7%	63.7%	1.6%	4.1%	(5.7%)
Apr	7.1%	23.1%	69.8%						
May	7.8%	23.5%	68.7%						
Jun	8.2%	23.8%	68.0%						
Jul	8.0%	24.1%	67.9%						
Aug	8.1%	23.9%	68.0%						
Sep	7.8%	23.9%	68.3%						
Oct	9.8%	29.0%	61.3%						
Nov	9.3%	29.1%	61.7%						
Dec	9.9%	25.6%	64.5%						
Annual	8.0%	24.5%	67.5%	9.2%	27.9%	62.9%	1.2%	3.4%	(4.6%)

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 as well as for conservative operations. 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 as well as units committed as part of conservative operations, excluding units that were committed for providing black start and reactive service. In January 2014, there was an increase in the offer capping percentages for units failing the TPS test and units committed for conservative operations while the number of units committed as offer capped for providing black start and reactive service decreased.

Table 3-20 Offer-capping statistics – Energy only: January through March, 2010 to 2014

	Real Time		Day Ahead	
(Jan-Mar)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2010	0.6%	0.2%	0.1%	0.0%
2011	0.4%	0.1%	0.0%	0.0%
2012	1.0%	0.5%	0.1%	0.2%
2013	0.3%	0.1%	0.1%	0.0%
2014	1.1%	0.4%	0.3%	0.2%

Table 3-21 shows the offer capping percentages including units committed to provide constraint relief and units committed to provide black start service and reactive support. The units that are committed and offer capped for reliability reasons have been 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. In the first three months of 2014, the percentage of hours when units that provided black start and reactive service were economic increased compared to the first three months of 2013 and the percentage of hours they were committed as offer capped decreased as a result.

Table 3-21 Offer-capping statistics for energy and reliability: January through March, 2010 to 2014

	Real Time		Day Ahead	
(Jan-Mar)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2010	0.6%	0.2%	0.1%	0.0%
2011	0.5%	0.1%	0.0%	0.0%
2012	1.5%	1.0%	0.1%	0.2%
2013	2.7%	1.9%	3.1%	1.8%
2014	1.5%	0.9%	0.8%	0.6%

Table 3-22 presents data on the frequency with which units were offer capped in the first three months of 2013 and the first quarter of 2014 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: January through March, 2013 and 2014[41]

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	(Jan - Mar)	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2014	0	0	0	0	0	3
	2013	0	0	0	0	0	17
80% and < 90%	2014	0	0	0	0	1	1
	2013	0	0	0	0	0	6
75% and < 80%	2014	0	0	0	1	2	2
	2013	0	0	0	0	0	3
70% and < 75%	2014	0	0	0	2	2	2
	2013	0	0	0	0	0	2
60% and < 70%	2014	0	0	0	0	8	7
	2013	0	0	0	0	0	9
50% and < 60%	2014	0	0	0	7	2	10
	2013	0	0	0	0	2	15
25% and < 50%	2014	0	0	0	1	9	56
	2013	0	0	0	0	0	21
10% and < 25%	2014	0	0	0	1	1	38
	2013	0	0	0	0	1	10

Table 3-22 shows that three units were offer capped for 90 percent or more of their run hours in the first quarter of 2014 compared to 13 units in the first quarter of 2013.

41 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.

Offer Capping for Local Market Power

In the first three months of 2014, the AEP, AP, ATSI, BGE, ComEd, DEOK, DLCO, Dominion, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL and PSEG control zones experienced congestion resulting from one or more constraints binding for 25 or more hours. The AECO, DAY, and RECO control zones did not have constraints binding for 25 or more hours in the first three months of 2014. Table 3-23 shows that AEP, AP, ComEd, and PSEG were the only control zones with 25 or more hours of congestion in every year in the first three months of 2009 through 2014.

Table 3-23 Numbers of hours when control zones experienced congestion for 25 or more hours: January through March, 2009 through 2014

	2009 (Jan - Mar)	2010 (Jan - Mar)	2011 (Jan - Mar)	2012 (Jan - Mar)	2013 (Jan - Mar)	2014 (Jan - Mar)
AECO	149	NA	70	40	32	NA
AEP	890	157	423	50	225	654
APS	525	260	579	105	64	309
ATSI	101	37	NA	1	46	428
BGE	NA	25	NA	650	214	29
ComEd	325	816	123	525	973	1,233
DEOK	NA	NA	NA	33	NA	68
DLCO	NA	83	NA	146	NA	211
Dominion	91	114	98	NA	111	207
DPL	43	NA	28	133	NA	297
JCPL	NA	NA	NA	NA	NA	44
Met-Ed	NA	NA	NA	NA	NA	34
PECO	30	NA	93	NA	77	327
PENELEC	NA	NA	29	32	29	179
Pepco	NA	NA	44	66	71	39
PPL	NA	NA	52	NA	103	41
PSEG	336	344	255	139	1,408	1,445

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 the first three months of 2014.[42] 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

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

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.

Table 3-24 Three pivotal supplier test details for interface constraints: January through March, 2014

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	354	349	13	1	12
	Off Peak	396	399	12	1	11
AEP - DOM	Peak	437	272	8	0	8
	Off Peak	323	211	7	0	7
AP South	Peak	414	468	9	0	9
	Off Peak	434	524	9	0	9
BC/PEPCO	Peak	603	614	7	0	6
	Off Peak	482	468	6	0	6
Bedington - Black Oak	Peak	215	188	13	1	12
	Off Peak	210	167	11	1	10
Central	Peak	422	63	6	0	6
	Off Peak	1,070	657	11	0	11
Eastern	Peak	426	295	8	0	8
	Off Peak	457	400	9	1	8
PL North	Peak	0	0	0	0	0
	Off Peak	83	303	1	0	1
Western	Peak	951	886	14	1	13
	Off Peak	894	937	13	1	12

The three pivotal supplier test is applied every time the PJM market system solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for capping. Only uncommitted resources, which would be started as a result of incremental relief needs, are eligible to be offer capped. Already committed units that can provide incremental relief cannot, regardless of test score, be switched from price to cost offers. Table 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: January through March, 2014

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	781	73	9%	1	0%	1%
	Off Peak	887	82	9%	2	0%	2%
AEP - DOM	Peak	63	5	8%	0	0%	0%
	Off Peak	238	29	12%	0	0%	0%
AP South	Peak	4,159	181	4%	0	0%	0%
	Off Peak	3,349	163	5%	1	0%	1%
BC/PEPCO	Peak	229	26	11%	0	0%	0%
	Off Peak	112	8	7%	0	0%	0%
Bedington - Black Oak	Peak	567	68	12%	1	0%	1%
	Off Peak	327	37	11%	0	0%	0%
Central	Peak	2	0	0%	0	0%	0%
	Off Peak	6	0	0%	0	0%	0%
Eastern	Peak	48	2	4%	0	0%	0%
	Off Peak	60	4	7%	0	0%	0%
PL North	Peak	0	0	0%	0	0%	0%
	Off Peak	402	0	0%	0	0%	0%
Western	Peak	1,156	132	11%	2	0%	2%
	Off Peak	627	35	6%	0	0%	0%

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.[43] 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.

43 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.

Real-Time Markup

Table 3-26 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category. The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point. In the first three months of 2014, 58.3 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.0. The data show that some marginal units did have substantial markups. The average data do not show the high markups that occurred for the very high load days in January[44]

Table 3-26 Average, real-time marginal unit markup index (By offer price category): January through March 2013 and 2014

	2013 (Jan - Mar)			2014 (Jan - Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.08)	($3.05)	18.0%	(0.16)	($2.25)	6.8%
$25 to $50	(0.02)	($1.98)	62.2%	0.00	($0.82)	51.5%
$50 to $75	0.02	$0.95	6.6%	0.03	$0.24	15.0%
$75 to $100	0.04	$3.42	1.5%	0.05	$2.40	4.2%
$100 to $125	0.02	$2.23	1.2%	0.11	$10.78	2.4%
$125 to $150	0.02	$2.26	0.9%	0.09	$10.66	2.6%
>= $150	0.01	$0.51	4.1%	0.11	$30.09	14.3%

Day-Ahead Markup

Table 3-27 Average day-ahead marginal unit markup index (By offer price category): January through March of 2013 and 2014

	2013 (Jan - Mar)			2014 (Jan - Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.05)	($1.56)	17.2%	(0.11)	($2.75)	10.0%
$25 to $50	(0.05)	($2.98)	76.9%	(0.02)	($1.56)	54.5%
$50 to $75	0.01	($2.52)	5.3%	0.03	$1.08	19.0%
$75 to $100	0.08	$7.07	0.5%	0.06	$4.45	3.5%
$100 to $125	0.00	$0.00	0.1%	0.13	$13.97	2.9%
$125 to $150	0.00	$0.00	0.0%	0.02	($2.02)	3.1%
>= $150	0.00	$0.00	0.0%	0.06	$12.56	7.0%

44 See the *2014 Quarterly State of the Market Report for PJM: January through March*, Section 3, "Participant Behavior during Cold Weather Days in January."

Table 3-27 shows the average markup index of marginal units in Day-Ahead Energy Market, by offer price category. In the first three months of 2014, 86.6 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.03. The data show that some marginal units did have substantial markups. The average markup index increased significantly, for example, from 0.00 in the first three months of 2013, to 0.13 in the first three months of 2014 in the offer price category from $100 to $125. However, in the first three months of 2014, there were 429 hours when the marginal units had offer prices of $100 or above and the highest markup was $392 per MWh.

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

An AU, or associated unit, is a unit that is physically, electrically and economically identical to an FMU, but does not qualify for the

45 OA, Schedule 1 § 6.4.2.
46 114 FERC ¶ 61, 076 (2006).
47 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).

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 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.[48]

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 2013 and the first three months of 2014. Of the 93 units eligible in at least one month during the first three months of 2014, 67 units (72.0 percent) were FMUs or AUs for all three months, and 11 units (11.8 percent) qualified in only one month in the first quarter of 2014.

Table 3-28 Frequently mitigated units and associated units total months eligible: 2013 and January through March, 2014

Months Adder-Eligible	2013	2014
1	10	11
2	22	15
3	14	67
4	10	
5	5	
6	8	
7	7	
8	3	
9	1	
10	2	
11	8	
12	22	
Total	112	93

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

Figure 3-20 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 349 unique units that have qualified for an FMU adder in at least one month. Of these 349 units, no unit qualified for an adder in all potential months. Two units qualified in 98 of the 99 possible months, and 92 of the 349 units (26.4 percent) have qualified for an adder in more than half of the possible months.

Figure 3-20 Frequently mitigated units and associated units total months eligible: February, 2006 through March, 2014

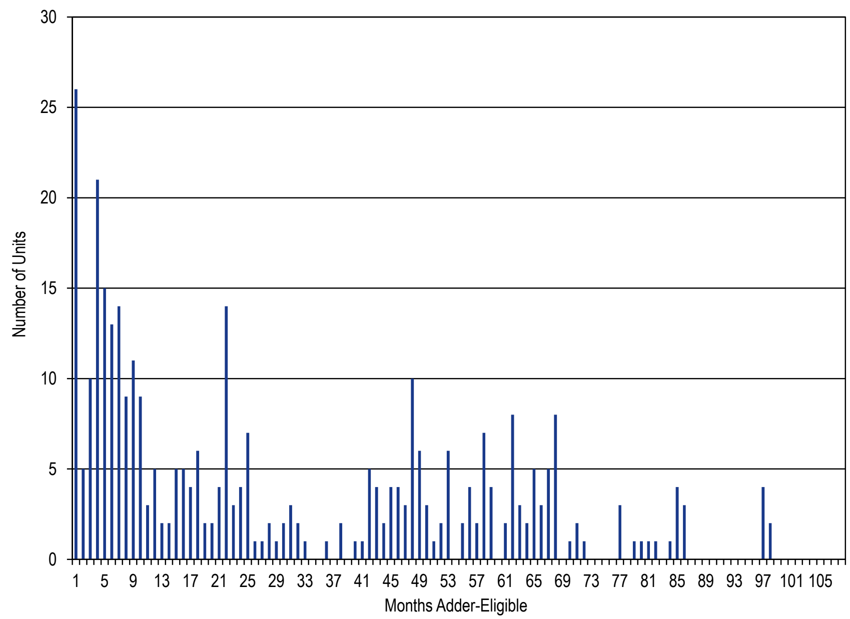


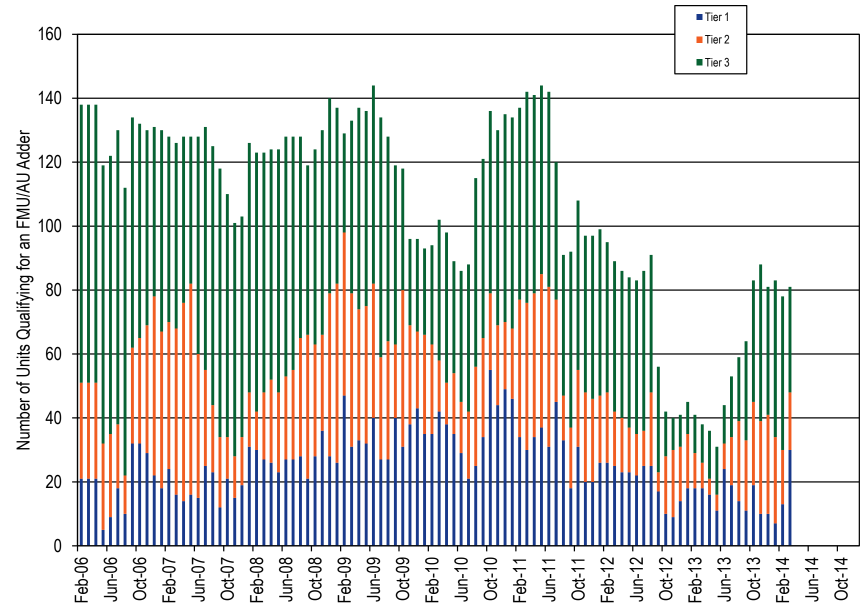
Table 3-29 shows, by month, the number of FMUs and AUs in 2013 and the first three months of 2014. For example, in January 2014, there were 7 FMUs and AUs in Tier 1, 27 FMUs and AUs in Tier 2, and 49 FMUs and AUs in Tier 3.

Table 3-29 Number of frequently mitigated units and associated units (By month): 2013 and January through March, 2014

	FMUs and AUs							
	2013				2014			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	18	17	10	45	7	27	49	83
February	18	11	12	41	13	17	48	78
March	18	8	12	38	30	18	33	81
April	16	5	15	36				
May	11	5	15	31				
June	24	8	12	44				
July	19	15	19	53				
August	14	25	20	59				
September	11	22	31	64				
October	19	26	38	83				
November	10	29	49	88				
December	10	31	40	81				

Figure 3-21 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 qualifying for an FMU or AU adder in the first quarter of 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 the first three months of 2013.

Figure 3-21 Frequently mitigated units and associated units (By month): February, 2006 through March, 2014



The PJM Tariff defines offer capped units as those capped to maintain system reliability as a result of limits on transmission capability.[49] 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.

49 PJM OATT. Attachment K – Appendix §6.4 Offer Price Caps., (Effective Date August 9, 2013), p. 1912.

The FMU adder was filed with FERC in 2005, and approved effective February 2006.[50] 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

50 110 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 on a list of 438 buses, eligible for up-to congestion transaction bidding.[51] Financial Transaction Rights (FTRs) bids may be submitted at any bus on a list of 1,915 buses, eligible for FTRs. Import and export transactions may be submitted at any interface pricing point, where an import is equivalent to a virtual offer that is injected into PJM and an export is equivalent to a virtual bid that is withdrawn from PJM.

Figure 3-22 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 the first three months of 2014.

51 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>.

Figure 3-22 PJM day-ahead aggregate supply curves: 2014 example day

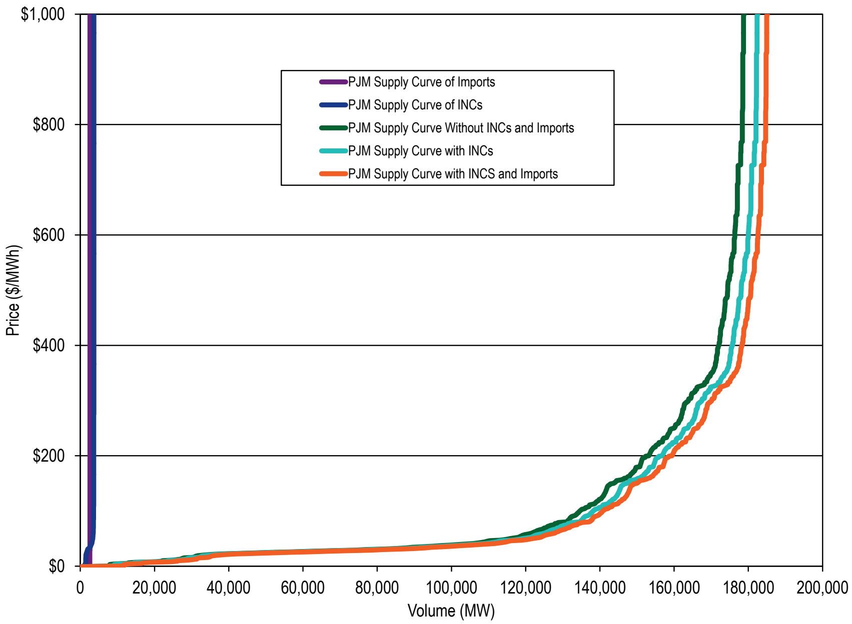


Table 3-31 shows the average hourly number of increment offers and decrement bids and the average hourly MW for 2013 and the first three months of 2014. In the first three months of 2014, the average hourly submitted and cleared increment offer MW decreased 41.8 and 46.5 percent, and the average hourly submitted and cleared decrement bid MW increased 1.6 and decreased 17.6 percent, compared to the first three months of 2013.

Table 3-31 Hourly average number of cleared and submitted INCs, DECs by month: January 2013 through March of 2014

		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
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
2014	Jan	3,086	4,165	69	214	5,844	8,372	81	322
2014	Feb	3,085	3,985	64	171	5,981	9,108	82	286
2014	Mar	2,942	3,890	66	179	6,702	9,455	96	291
2014	Annual	3,036	4,014	66	189	6,182	8,974	87	300

In the first three months of 2014, 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 2013 and the first three months of 2014. In the first three months of 2014, the average hourly up-to congestion submitted MW increased 44.3 percent and cleared MW increased 32.4 percent, compared to the first three months of 2013.

Table 3-32 Hourly average of cleared and submitted up-to congestion bids by month: January 2013 through March of 2014

		Up-to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
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
2014	Jan	55,969	199,708	2,436	7,056
2014	Feb	64,123	229,256	3,262	9,020
2014	Mar	65,829	243,469	3,521	10,920
2014	Annual	61,900	223,965	3,066	8,997

Table 3-33 shows the average hourly number of import and export transactions and the average hourly MW for 2013 and the first three months of 2014. In the first three months of 2014, the average hourly submitted and cleared import transaction MW increased 17.0 and 17.1 percent, and the average hourly submitted and cleared export transaction MW increased 38.9 and 30.2 percent, compared to the first three months of 2013.[52]

52 For more information about imports and exports, see the *2014 Quarterly State of the Market Report for PJM: January through March*, Section 9, "Interchange Transactions," Interchange Transaction Activity.

Table 3-33 Hourly average number of cleared and submitted import and export transactions by month: January 2013 through March of 2014

		Imports				Exports			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
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
2014	Jan	2,347	2,515	14	15	3,495	3,887	21	24
2014	Feb	2,419	2,616	13	15	4,299	4,584	24	26
2014	Mar	2,450	2,496	15	15	5,069	5,293	27	29
2014	Annual	2,405	2,540	14	15	4,287	4,588	24	26

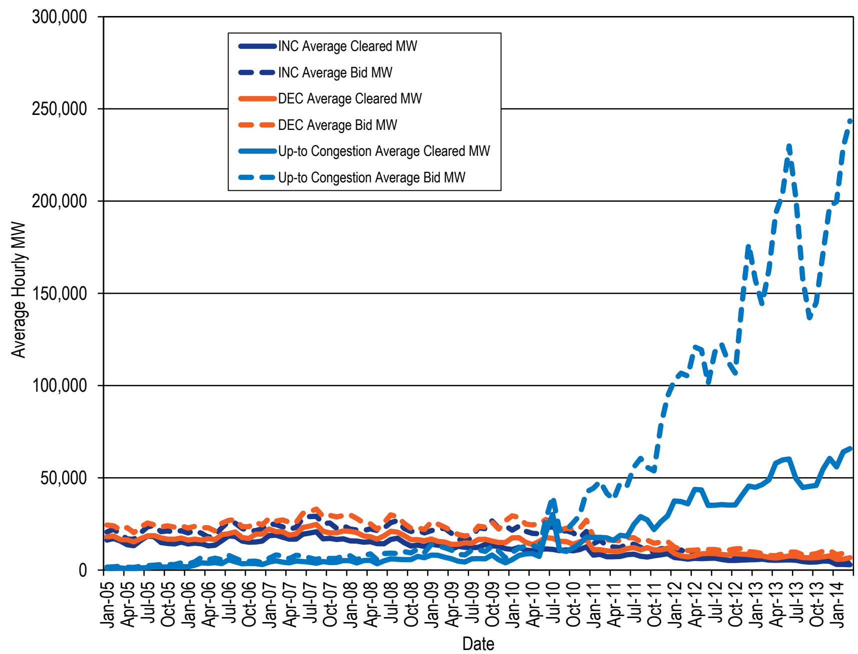
Table 3-34 shows the frequency with which generation offers, import or export transactions, up-to congestion transactions, decrement bids, increment offers and price-sensitive demand are marginal for each month.

Table 3-34 Type of day-ahead marginal units: January through March of 2014

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	2.7%	0.1%	94.5%	1.4%	1.2%	0.0%
Feb	2.0%	0.3%	94.8%	1.9%	1.1%	0.0%
Mar	2.5%	0.2%	94.7%	1.5%	1.0%	0.0%
Annual	2.4%	0.2%	94.7%	1.6%	1.1%	0.0%

Figure 3-23 shows the hourly volume of bid and cleared INC, DEC and up-to congestion bids by month.

Figure 3-23 Hourly number of bid and cleared INC, DEC and Up-to Congestion bids (MW) by month: January 2005 through March 2014



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 the first three months of 2013 and the first three months of 2014, the total increment offers and decrement bids by whether the parent organization is financial or physical. Table 3-36 shows, for the first three months of 2013 and the first three months of 2014, the total up-to congestion transactions by the type of parent organization. Table 3-37 shows, for the first three months of 2013, and the first three months of 2014, 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 64.9 percent of all the cleared up-to congestion MW in PJM in the first three months of 2014, which is 1.3 percent higher than 63.6 percent in the first three months of 2013. The cleared up-to congestion MW from financial companies increased 37.5 percent in the first three months of 2014 compared to the first three months of 2013. At the same time, the cleared up-to congestion MW from physical companies decreased by 44.9 percent decrease in the first three months of 2014 compared to the first three months for 2013. The average hourly price difference between day-ahead and real-time markets increased from $0.13 in the first three months of 2013 to $2.48 in the first three months of 2014. On average, real-time prices were lower than day-ahead prices.

Table 3-35 PJM INC and DEC bids by type of parent organization (MW): January through March of 2013 and 2014

	2013 (Jan -Mar)		2014 (Jan -Mar)	
Category	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	7,803,420	23.0%	10,927,507	39.0%
Physical	26,141,745	77.0%	17,113,625	61.0%
Total	33,945,165	100.0%	28,041,132	100.0%

Table 3-36 PJM up-to congestion transactions by type of parent organization (MW): January through March of 2013 and 2014

	2013 (Jan -Mar)		2014 (Jan -Mar)	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	94,709,907	93.8%	130,218,478	97.4%
Physical	6,211,701	6.2%	3,424,344	2.6%
Total	100,921,609	100.0%	133,642,822	100.0%

Table 3-37 PJM import and export transactions by type of parent organization (MW): January through March of 2013 and 2014

	2013 (Jan -Mar)		2014 (Jan -Mar)	
Category	Total Import and Export MW	Percentage	Total Import and Export MW	Percentage
Financial	4,815,804	41.7%	5,156,254	35.7%
Physical	6,728,468	58.3%	9,292,636	64.3%
Total	11,544,272	100.0%	14,448,890	100.0%

Table 3-38 shows increment offers and decrement bids bid by top ten locations for the first three months of 2013 and the first three months of 2014.

Table 3-38 PJM virtual offers and bids by top ten locations (MW): January through March of 2013 and 2014

2013 (Jan-Mar)					2014 (Jan-Mar)				
Aggregate/Bus Name	Aggregate/ Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	6,709,062	7,469,243	14,178,305	WESTERN HUB	HUB	2,223,221	2,647,608	4,870,829
SOUTHIMP	INTERFACE	2,451,598	0	2,451,598	MISO	INTERFACE	209,057	1,977,536	2,186,593
N ILLINOIS HUB	HUB	601,071	1,406,425	2,007,496	SOUTHIMP	INTERFACE	2,084,131	0	2,084,131
AEP-DAYTON HUB	HUB	855,706	915,790	1,771,496	PPL	ZONE	32,642	1,769,804	1,802,446
IMO	INTERFACE	1,415,648	26,744	1,442,392	PECO	ZONE	23,212	1,468,188	1,491,399
PPL	ZONE	21,829	1,416,128	1,437,957	AEP-DAYTON HUB	HUB	507,558	692,252	1,199,810
PECO	ZONE	37,216	850,576	887,793	IMO	INTERFACE	1,052,534	134,001	1,186,535
NYIS	INTERFACE	74,855	589,255	664,110	N ILLINOIS HUB	HUB	92,393	755,876	848,269
MISO	INTERFACE	53,127	535,276	588,403	BGE	ZONE	5,154	723,097	728,251
DOMINION HUB	HUB	99,832	370,797	470,629	NYIS	INTERFACE	239,483	327,127	566,610
Top ten total		12,319,944	13,580,235	25,900,179			6,469,386	10,495,489	16,964,874
PJM total		14,879,528	19,065,637	33,945,165			8,667,100	19,374,032	28,041,132
Top ten total as percent of PJM total		82.8%	71.2%	76.3%			74.6%	54.2%	60.5%

Table 3-39 shows up-to congestion transactions by import bids for the top ten locations for the first three months of 2013 and the first three months of 2014.[53]

Table 3-39 PJM cleared up-to congestion import bids by top ten source and sink pairs (MW): January through March of 2013 and 2014

2013 (Jan-Mar)				
Imports				
Source	Source Type	Sink	Sink Type	MW
NYIS	INTERFACE	HUDSON BC	AGGREGATE	403,639
OVEC	INTERFACE	DEOK	ZONE	381,127
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	311,221
OVEC	INTERFACE	STUART 1	AGGREGATE	243,555
MISO	INTERFACE	112 WILTON	EHVAGG	236,497
OVEC	INTERFACE	ZIMMER	AGGREGATE	219,178
OVEC	INTERFACE	CONESVILLE 5	AGGREGATE	191,405
OVEC	INTERFACE	BECKJORD 6	AGGREGATE	173,209
OVEC	INTERFACE	OHIO HUB	HUB	172,597
OVEC	INTERFACE	STUART 4	AGGREGATE	170,534
Top ten total				2,502,961
PJM total				11,003,102
Top ten total as percent of PJM total				22.7%
2014 (Jan-Mar)				
Imports				
Source	Source Type	Sink	Sink Type	MW
HUDSONTP	INTERFACE	LEONIA 230 T-2	AGGREGATE	276,634
NEPTUNE	INTERFACE	SOUTHRIV 230	AGGREGATE	249,140
OVEC	INTERFACE	STUART DIESEL	AGGREGATE	220,925
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	192,686
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	183,006
HUDSONTP	INTERFACE	LEONIA 230 T-1	AGGREGATE	160,200
IMO	INTERFACE	GIRARD	AGGREGATE	153,819
OVEC	INTERFACE	DEOK	ZONE	133,531
MISO	INTERFACE	COOK	EHVAGG	130,340
NIPSCO	INTERFACE	COOK	EHVAGG	127,933
Top ten total				1,828,213
PJM total				8,795,248
Top ten total as percent of PJM total				20.8%

Table 3-40 shows up-to congestion transactions by export bids for the top ten locations for the first three months of 2013 and the first three months of 2014.

Table 3-40 PJM cleared up-to congestion export bids by top ten source and sink pairs (MW): January through March of 2013 and 2014

2013 (Jan-Mar)				
Exports				
Source	Source Type	Sink	Sink Type	MW
GAVIN	EHVAGG	OVEC	INTERFACE	440,608
F387 CHICAGOH	AGGREGATE	NIPSCO	INTERFACE	368,347
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	350,741
SPORN 3	AGGREGATE	OVEC	INTERFACE	293,548
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	253,264
JEFFERSON	EHVAGG	OVEC	INTERFACE	249,922
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	194,734
CULLODEN	EHVAGG	OVEC	INTERFACE	188,867
21 KINCA ATR24304	AGGREGATE	OVEC	INTERFACE	182,977
BIG SANDY CT4	AGGREGATE	SOUTHWEST	INTERFACE	166,899
Top ten total				2,689,906
PJM total				14,919,573
Top ten total as percent of PJM total				18.0%
2014 (Jan-Mar)				
Exports				
Source	Source Type	Sink	Sink Type	MW
TANNERS CRK 4	AGGREGATE	SOUTHWEST	INTERFACE	651,512
JEFFERSON	EHVAGG	OVEC	INTERFACE	468,549
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	311,829
F387 CHICAGOH	AGGREGATE	NIPSCO	INTERFACE	254,303
TANNERS CRK 4	AGGREGATE	OVEC	INTERFACE	237,716
LINDEN A	AGGREGATE	LINDENVFT	INTERFACE	218,640
STUART 1	AGGREGATE	OVEC	INTERFACE	196,328
JEFFERSON	EHVAGG	SOUTHWEST	INTERFACE	185,146
EAST BEND 2	AGGREGATE	SOUTHWEST	INTERFACE	156,573
EAST BEND 2	AGGREGATE	SOUTHEXP	INTERFACE	131,940
Top ten total				2,812,535
PJM total				9,713,595
Top ten total as percent of PJM total				29.0%

53 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 the first three months of 2013 and the first three months of 2014.

Table 3-41 PJM cleared up-to congestion wheel bids by top ten source and sink pairs (MW): January through March of 2013 and 2014

2013 (Jan-Mar)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	438,456
IMO	INTERFACE	NYIS	INTERFACE	198,859
MISO	INTERFACE	NIPSCO	INTERFACE	133,002
LINDENVFT	INTERFACE	NYIS	INTERFACE	76,636
MISO	INTERFACE	SOUTHEXP	INTERFACE	53,205
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	51,723
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	41,180
NORTHWEST	INTERFACE	MISO	INTERFACE	40,196
MISO	INTERFACE	OVEC	INTERFACE	33,088
NYIS	INTERFACE	LINDENVFT	INTERFACE	27,935
Top ten total				1,094,280
PJM total				1,342,254
Top ten total as percent of PJM total				81.5%
2014 (Jan-Mar)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
NORTHWEST	INTERFACE	MISO	INTERFACE	481,592
OVEC	INTERFACE	SOUTHEXP	INTERFACE	153,591
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	81,357
MISO	INTERFACE	SOUTHEXP	INTERFACE	46,478
MISO	INTERFACE	NORTHWEST	INTERFACE	40,072
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	39,296
IMO	INTERFACE	NYIS	INTERFACE	38,877
MISO	INTERFACE	NIPSCO	INTERFACE	30,325
SOUTHIMP	INTERFACE	MISO	INTERFACE	22,863
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	19,979
Top ten total				954,430
PJM total				1,165,420
Top ten total as percent of PJM total				81.9%

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.[54] Up-to congestion transactions can now be made at internal buses. The top ten internal up-to congestion transaction locations were 12.2 percent of the PJM total internal up-to congestion transactions in the first three months of 2014.

Table 3-42 shows up-to congestion transactions by internal bids for the top ten locations for the first three months of 2013 and 2014.

Table 3-42 PJM cleared up-to congestion internal bids by top ten source and sink pairs (MW): January through March of 2013 and 2014

2013 (Jan-Mar)				
Internal				
Source	Source Type	Sink	Sink Type	MW
SUNBURY 1-3	AGGREGATE	CITIZENS	AGGREGATE	1,298,253
YADKIN	EHVAGG	FENTRESS	EHVAGG	763,731
NAPERVILLE	AGGREGATE	WINNETKA	AGGREGATE	600,547
CORDOVA	AGGREGATE	QUAD CITIES 2	AGGREGATE	563,064
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	501,756
BROADFORD	EHVAGG	CLINCH RIVER 1	AGGREGATE	487,787
NAPERVILLE	AGGREGATE	ZION 1	AGGREGATE	487,593
DELI	AGGREGATE	BYRON 1	AGGREGATE	461,131
GENEVA	AGGREGATE	WINNETKA	AGGREGATE	377,375
NAPERVILLE	AGGREGATE	CHICAGO HUB	HUB	358,100
Top ten total				5,899,339
PJM total				73,656,680
Top ten total as percent of PJM total				8.0%
2014 (Jan-Mar)				
Internal				
Source	Source Type	Sink	Sink Type	MW
VERNON BK 4	AGGREGATE	AEC - JC	AGGREGATE	2,100,641
MOUNTAINEER	EHVAGG	GAVIN	EHVAGG	2,058,717
ATSI GEN HUB	HUB	ATSI	ZONE	1,913,421
MOUNTAINEER	EHVAGG	FLATLICK	EHVAGG	1,832,053
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	1,289,602
CLOVERDALE	EHVAGG	JOSHUA FALLS	EHVAGG	1,103,000
KENDALL 3 CC	AGGREGATE	KENDALL 1-2	AGGREGATE	1,070,596
WYOMING	EHVAGG	BROADFORD	EHVAGG	1,011,581
TANNERS CRK 4	AGGREGATE	STUART DIESEL	AGGREGATE	768,507
N ILLINOIS HUB	HUB	AEP-DAYTON HUB	HUB	729,308
Top ten total				13,877,425
PJM total				113,968,559
Top ten total as percent of PJM total				12.2%

54 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 shows the number of source-sink pairs that were offered and cleared monthly in January of 2012 through the first three months of 2014. 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 continuing through the first three months of 2014 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.

Table 3-43 Number of PJM offered and cleared source and sink pairs: January 2012 through March 2014

		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
2014	Jan	7,977	11,191	5,179	7,714
2014	Feb	10,087	11,688	7,173	8,463
2014	Mar	11,360	14,745	7,284	9,943
2014	Annual	9,799	14,745	6,524	9,943

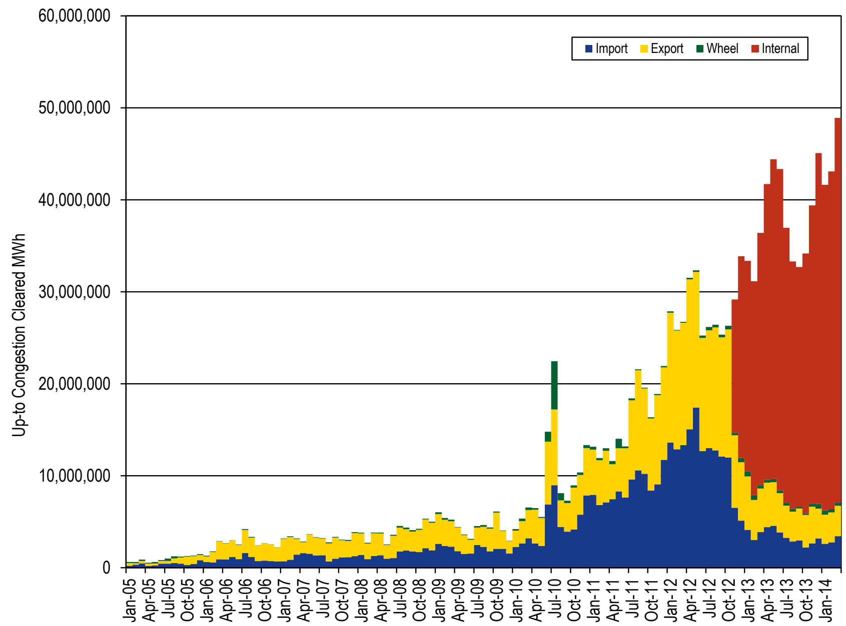
Table 3-44 and Figure 3-24 show total cleared up-to congestion transactions by type for the first three months of 2013 and the first three months of 2014. Internal up-to congestion transactions in the first three months of 2014 were 85.3 percent of all up-to congestion transactions for the first three months of 2014. In the first three months of 2014, the top ten internal up-to congestion transactions were the top ten total up-to congestion transactions in MW.

Table 3-44 PJM cleared up-to congestion transactions by type (MW): January through March of 2013 and 2014

	2013 (Jan-Mar)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	2,502,961	2,689,906	1,094,280	5,899,339	6,042,928
PJM total (MW)	11,003,102	14,919,573	1,342,254	73,656,680	100,921,609
Top ten total as percent of PJM total	22.7%	18.0%	81.5%	8.0%	6.0%
PJM total as percent of all up-to congestion transactions	10.9%	14.8%	1.3%	73.0%	100.0%
	2014 (Jan-Mar)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	1,828,213	2,812,535	954,430	13,877,425	13,877,425
PJM total (MW)	8,795,248	9,713,595	1,165,420	113,968,559	133,642,822
Top ten total as percent of PJM total	20.8%	29.0%	81.9%	12.2%	10.4%
PJM total as percent of all up-to congestion transactions	6.6%	7.3%	0.9%	85.3%	100.0%

Figure 3-24 shows the initial increase and continued rise of internal up-to congestion transactions in November and December of 2012, and the first three months of 2014, following the November 1, 2012 rule change permitting such transactions.

Figure 3-24 PJM cleared up-to congestion transactions by type (MW): January 2005 through March 2014



Generator Offers

Generator offers are categorized as dispatchable (Table 3-45) or self scheduled (Table 3-46).[55] Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are self scheduled and must run. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are self scheduled and dispatchable. Table 3-45 and Table 3-46 do not include units that did not indicate their offer status and units that were offered as available to run only during emergency events. The MW offered beyond the economic range of a unit, i.e. MW range between the specified economic maximum and emergency maximum, are categorized as emergency MW. The emergency MW are included in both tables.

Table 3-45 shows the proportion of MW offers by dispatchable units, by unit type and by offer price range, for the first three months of 2014. For example, 61.0 percent of CC offers were dispatchable and in the $0 to $200 per MWh price range. The Total column is the proportion of all MW offers by unit type that were dispatchable. For example, 80.4 percent of all CC MW offers were dispatchable, including the 7.9 percent of emergency MW offered by CC units. The All Dispatchable Offers row is the proportion of MW that were offered as available for economic dispatch within a given range by all unit types. For example, 37.1 percent of all dispatchable offers were in the $0 to $200 per MWh price range. The Total column in the All Dispatchable Offers row is the proportion of all MW offers that were offered as available for economic dispatch, including emergency MW. Among all the generator offers in the first three months of 2014, 54.4 percent were offered as available for economic dispatch.

55 Each range in the tables is greater than or equal to the lower value and less than the higher value. The unit type battery is not included in these tables because batteries do not make energy offers. The unit type fuel cell is not included in these tables because of the small number owners and the small number of units of this type of generation.

Table 3-45 Distribution of MW for dispatchable unit offer prices: January through March of 2014

	Dispatchable (Range)							
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	0.0%	61.0%	6.3%	2.7%	0.9%	1.6%	7.9%	80.4%
CT	0.0%	40.9%	34.2%	8.6%	2.7%	1.9%	10.8%	99.1%
Diesel	0.0%	15.1%	26.3%	7.9%	2.6%	2.0%	15.0%	68.9%
Run of River	0.0%	10.9%	0.0%	0.0%	0.0%	0.0%	0.0%	10.9%
Nuclear	7.2%	29.6%	0.0%	0.0%	0.0%	0.0%	10.8%	47.6%
Pumped Storage	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Solar	0.5%	4.1%	0.0%	0.0%	0.0%	0.0%	0.0%	4.6%
Steam	0.0%	42.3%	2.7%	0.5%	0.1%	0.3%	3.7%	49.5%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	38.4%	7.4%	0.0%	0.0%	0.0%	0.0%	0.5%	46.3%
All Dispatchable Offers	0.9%	37.1%	8.0%	2.1%	0.7%	0.7%	4.9%	54.4%

Table 3-46 shows the proportion of MW offers by unit type that were self scheduled to generate fixed output and by unit type and price range for self-scheduled and dispatchable units, for the first three months of 2014. For example, 15.8 percent of CC offers were self scheduled and dispatchable and in the $0 to $200 price range. The Total column is the proportion of all MW offers by unit type that were self scheduled to generate fixed output and are self scheduled and dispatchable. For example, 19.6 percent of all CC MW offers were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including the 2.2 percent of emergency MW offered by CC units. The All Self-Scheduled Offers row is the proportion of MW that were offered as either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum within a given range by all unit types. For example, units that were self scheduled to generate at fixed output accounted for 19.7 percent of all offers and self-scheduled and dispatchable units accounted for 21.2 percent of all offers. The Total column in the All Self-Scheduled Offers row is the proportion of all MW offers that were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including emergency MW. Among all the generator offers in the first three months of 2014, 45.6 percent were offered as self scheduled.

Table 3-46 Distribution of MW for self scheduled offer prices: January through March of 2014

	Self Scheduled		Self Scheduled and Dispatchable (Range)							
Unit Type	Must Run	Emergency	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	0.7%	0.3%	0.0%	15.8%	0.6%	0.2%	0.1%	0.1%	1.8%	19.6%
CT	0.5%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%
Diesel	27.0%	4.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	31.1%
Hydro	81.5%	7.1%	0.1%	0.3%	0.0%	0.0%	0.0%	0.0%	0.1%	89.1%
Nuclear	25.8%	10.1%	2.4%	4.0%	0.0%	0.0%	0.0%	0.0%	10.2%	52.4%
Pumped Storage	59.4%	16.6%	4.3%	12.6%	0.0%	0.0%	0.0%	1.8%	5.1%	99.8%
Solar	71.0%	23.4%	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	95.4%
Steam	4.5%	1.2%	0.2%	41.0%	0.1%	0.0%	0.0%	0.0%	3.4%	50.5%
Transaction	86.5%	13.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	5.5%	5.0%	34.8%	3.0%	0.0%	0.0%	0.0%	0.0%	5.5%	53.7%
All Self-Scheduled Offers	19.7%	2.5%	0.8%	20.1%	0.1%	0.0%	0.0%	0.0%	2.2%	45.6%

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.[56]

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

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 3-47 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 3-47 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 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 some or all 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.[57]

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.

Table 3-47 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 $0.13 in the first quarter of 2013 to $7.12 in the first quarter of 2014. The adjusted markup contribution of coal units in the first quarter of 2014 was $4.19. The adjusted mark-up component of all gas-fired units in the first quarter of 2014 was $2.28. Coal units accounted for 59 percent of the increased markup component of LMP in the first three months of 2014 while gas units accounted for 32 percent.[58] 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 the first quarter of 2014, among the wind units that were marginal, 1.4 percent had positive offer prices.

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

58 See the *2014 Quarterly State of the Market Report for PJM: January through March*, Section 3, "Real-Time Markup on High Demand Days in January."

Table 3-47 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through March 2013 and 2014[59]

		2013 (Jan-Mar)		2014 (Jan-Mar)	
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	($1.01)	$0.76	$2.60	$4.19
Demand Response	Demand Response	$0.00	$0.00	$0.00	$0.00
Gas	CC	($0.79)	($0.79)	$0.90	$0.90
Gas	CT	$0.08	$0.08	$1.06	$1.06
Gas	Diesel	$0.00	$0.00	$0.08	$0.08
Gas	Fuel Cell	$0.00	$0.00	$0.00	$0.00
Gas	Steam	$0.07	$0.07	$0.24	$0.24
Municipal Waste	Diesel	$0.00	$0.00	$0.00	$0.00
Municipal Waste	Steam	$0.00	$0.00	$0.55	$0.55
Oil	CT	($0.00)	($0.00)	$0.07	$0.07
Oil	Diesel	$0.00	$0.00	$0.14	$0.14
Oil	Steam	($0.00)	($0.00)	($0.19)	($0.19)
Other	Solar	$0.00	$0.00	$0.00	$0.00
Other	Steam	($0.00)	($0.00)	$0.01	$0.01
Uranium	Steam	$0.00	$0.00	$0.02	$0.02
Wind	Wind	$0.01	$0.01	$0.04	$0.04
Total		($1.64)	$0.13	$5.52	$7.12

Markup Component of Real-Time Price

Table 3-48 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on-peak and off-peak prices. Table 3-49 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on-peak and off-peak prices. In the first quarter of 2014, when using unadjusted cost offers, $5.52 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-offers, $7.12 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first quarter of 2014, the markup component was highest in January, $6.51 per MWh using unadjusted cost offers and $8.12 per MWh using adjusted cost offers. This corresponds to 5.1 percent and 6.4 percent of the real time load-weighted average LMP in January. The January results demonstrate that markups can increase significantly during high demand periods but the monthly average results do not show the hourly markup component of LMP during high load hours. For some hours in January, the mark-up component of LMP was as high as $800 per MWh.

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

Table 3-48 Monthly markup components of real-time load-weighted LMP (Unadjusted): January through March 2013 and 2014

	2013			2014		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($3.12)	($3.86)	**($2.43)**	$6.51	$4.40	$8.52
Feb	($1.98)	($3.16)	**($0.83)**	$3.77	$1.01	$6.42
Mar	$0.26	($1.05)	**$1.62**	$6.13	$3.82	$8.54
Total	($1.64)	($2.69)	**($0.61)**	$5.52	$3.16	$7.86

Table 3-49 Monthly markup components of real-time load-weighted LMP (Adjusted): January through March, 2013 and 2014

	2013			2014		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($1.28)	($1.88)	($0.72)	$8.12	$6.41	$9.77
Feb	($0.19)	($1.24)	$0.83	$5.55	$2.78	$8.21
Mar	$1.93	$0.73	$3.19	$7.51	$5.57	$9.54
Total	$0.13	($0.79)	$1.03	$7.12	$5.01	$9.20

Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone for the first quarter of 2014 and the first quarter of 2013 in Table 3-50 and for adjusted offers in Table 3-51. The smallest zonal all hours average markup component using unadjusted offers for the first quarter of 2014 was in the DEOK Zone, $3.09 per MWh, while the highest was in the RECO Control Zone, $10.01 per MWh. The smallest zonal on peak average markup was in the DLCO Control Zone, $4.38 per MWh, while the highest was in the RECO Control Zone, $13.60 per MWh.

Table 3-50 Average real-time zonal markup component (Unadjusted): January through March, 2013 and 2014

	2013 (Jan - Mar)			2014 (Jan - Mar)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	($1.96)	($2.91)	($1.01)	$6.00	$2.56	$9.44
AEP	($1.58)	($2.28)	($0.87)	$5.57	$2.53	$8.64
APS	($1.69)	($2.73)	($0.64)	$4.13	$3.00	$5.28
ATSI	($1.71)	($2.39)	($1.06)	$3.82	$2.22	$5.39
BGE	($1.69)	($3.21)	($0.15)	$6.92	$5.39	$8.45
ComEd	($1.76)	($2.74)	($0.83)	$3.31	$2.18	$4.40
DAY	($1.72)	($2.39)	($1.07)	$3.16	$1.61	$4.66
DEOK	($1.74)	($2.42)	($1.08)	$3.09	$1.36	$4.80
DLCO	($1.68)	($2.44)	($0.94)	$3.62	$2.85	$4.38
DPL	($2.06)	($3.02)	($1.07)	$6.42	$2.08	$10.77
Dominion	($1.54)	($3.03)	$0.01	$8.46	$5.02	$11.92
EKPC	NA	NA	NA	$4.05	$2.08	$6.12
JCPL	($1.30)	($3.12)	$0.41	$5.18	$2.23	$7.98
Met-Ed	($1.72)	($2.76)	($0.71)	$5.58	$3.06	$8.02
PECO	($2.06)	($2.90)	($1.24)	$6.00	$3.06	$8.87
PENELEC	($1.58)	($2.53)	($0.67)	$4.92	$3.10	$6.68
PPL	($1.88)	($2.92)	($0.87)	$6.27	$3.24	$9.24
PSEG	($0.86)	($2.39)	$0.59	$8.18	$4.88	$11.32
Pepco	($1.55)	($3.02)	($0.13)	$7.03	$5.36	$8.65
RECO	($0.12)	($1.73)	$1.32	$10.01	$6.04	$13.60

Table 3-51 Average real-time zonal markup component (Adjusted): January through March, 2013 and 2014

	2013 (Jan - Mar)			2014 (Jan - Mar)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	($0.20)	($1.01)	$0.61	$7.61	$4.45	$10.76
AEP	$0.20	($0.39)	$0.80	$7.41	$4.31	$10.56
APS	$0.09	($0.83)	$1.01	$5.59	$4.80	$6.39
ATSI	$0.15	($0.49)	$0.75	$5.60	$4.15	$7.03
BGE	$0.13	($1.14)	$1.41	$8.53	$7.41	$9.66
ComEd	($0.03)	($1.00)	$0.90	$4.49	$3.93	$5.04
DAY	$0.14	($0.47)	$0.74	$4.72	$3.52	$5.89
DEOK	$0.04	($0.58)	$0.64	$4.57	$3.19	$5.93
DLCO	$0.10	($0.62)	$0.80	$5.34	$4.77	$5.89
DPL	($0.25)	($1.08)	$0.59	$7.54	$3.61	$11.49
Dominion	$0.24	($1.04)	$1.56	$10.18	$6.81	$13.57
EKPC	$0.00	$0.00	$0.00	$5.50	$3.92	$7.16
JCPL	$0.41	($1.20)	$1.92	$6.86	$4.29	$9.30
Met-Ed	$0.04	($0.86)	$0.90	$7.15	$5.00	$9.24
PECO	($0.30)	($1.02)	$0.40	$7.61	$5.05	$10.11
PENELEC	$0.22	($0.65)	$1.06	$6.49	$4.93	$7.99
PPL	($0.15)	($1.07)	$0.76	$7.83	$5.16	$10.45
PSEG	$0.76	($0.55)	$2.00	$9.75	$6.74	$12.61
Pepco	$0.22	($0.98)	$1.38	$8.60	$7.35	$9.80
RECO	$1.49	$0.22	$2.63	$11.61	$7.73	$15.11

Markup by Real Time Price Levels

Table 3-52 shows 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 3-52 Average real-time markup component (By price category, unadjusted): January through March, 2013 and 2014

	2013 (Jan - Mar)		2014 (Jan - Mar)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.24)	8.5%	($0.03)	0.9%
$25 to $50	($1.67)	83.0%	($0.84)	51.4%
$50 to $75	$0.25	5.5%	$0.36	20.7%
$75 to $100	$0.05	1.5%	$0.84	7.8%
$100 to $125	($0.07)	0.8%	$0.45	4.2%
$125 to $150	($0.02)	0.2%	$0.43	3.3%
>= $150	$0.04	0.4%	$4.45	11.7%

Table 3-53 Average real-time markup component (By price category, adjusted): January through March, 2013 and 2014

	2013 (Jan - Mar)		2014 (Jan - Mar)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.13)	8.5%	($0.01)	0.9%
$25 to $50	($0.10)	83.0%	$0.07	51.4%
$50 to $75	$0.32	5.5%	$0.65	20.7%
$75 to $100	$0.07	1.5%	$0.94	7.8%
$100 to $125	($0.05)	0.8%	$0.49	4.2%
$125 to $150	($0.02)	0.2%	$0.46	3.3%
>= $150	$0.04	0.4%	$4.71	11.7%

Day-Ahead Markup

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

The markup component of the PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 3-54. INC, DEC and up-to congestion transactions have zero markups. Up-to congestion transactions were marginal for 94.7 percent of marginal resources in the first quarter of 2014. INCs were marginal for 1.1 percent of marginal resources and DECs were marginal for 1.6 percent of marginal resources in the first quarter of 2014. 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 3-54 shows the markup component of LMP for marginal generating resources. Generating resources were marginal in only 2.4 percent of marginal resources in the first quarter of 2014. The markup component of LMP for marginal generating resources increased in all categories. The markup component of LMP for coal units increased from -$1.35 in the first three months of 2013 to $1.36 in the first three months of 2014, of which $0.69 occurred on days for which PJM declared maximum emergency generation alerts. The markup component of LMP for gas-fired CTs increased from -$0.06 in the first three months of 2013 to $0.20 in the first three months of 2014, of which $0.12 occurred on days for which PJM declared maximum emergency generation alerts.

Table 3-54 Markup component of the annual PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through March of 2013 and 2014

		2013 (Jan - Mar)		2014 (Jan - Mar)	
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	($1.35)	($0.50)	$1.36	$1.70
Gas	CT	($0.06)	($0.06)	$0.20	$0.20
Gas	Diesel	$0.00	$0.00	$0.00	$0.00
Gas	Steam	($1.32)	($1.32)	($1.20)	($1.20)
Municipal Waste	Steam	($0.00)	($0.00)	$0.00	$0.00
Oil	CT	$0.00	$0.00	$0.02	$0.02
Oil	Steam	($0.01)	($0.01)	$0.01	$0.01
Wind	Wind	$0.00	$0.00	$0.00	$0.00
Total		($2.74)	($1.89)	$0.39	$0.73

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 3-55 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted offers. Table 3-56 shows the markup component of average prices and of average monthly on-peak and off-peak prices using adjusted offers.

Table 3-55 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January through March of 2013 and 2014

	2013 (Jan - Mar)			2014 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($3.77)	($3.99)	($3.54)	$0.67	$2.17	($0.90)
Feb	($2.53)	($1.43)	($3.67)	$0.34	$2.07	($1.47)
Mar	($1.84)	($0.18)	($3.45)	$0.11	($0.33)	$0.53
Annual	($2.74)	($1.94)	($3.55)	$0.39	$1.36	($0.61)

Table 3-56 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: January through March of 2013 and 2014

	2013 (Jan - Mar)			2014 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($2.66)	($3.01)	($2.28)	$1.03	$2.34	($0.35)
Feb	($1.67)	($0.67)	($2.70)	$0.57	$2.21	($1.16)
Mar	($1.29)	$0.07	($2.61)	$0.55	($0.07)	$1.14
Annual	($1.89)	($1.27)	($2.53)	$0.73	$1.55	($0.11)

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 3-57. The markup component of annual average day-ahead price using adjusted offers is shown for each zone in Table 3-58. The markup component of the average day-ahead price increased in all zones from the first three months of 2013 to the first three months of 2014.

Table 3-57 Day-ahead, average, zonal markup component (Unadjusted): January through March of 2013 and 2014

	2013 (Jan - Mar)			2014 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($2.98)	($2.31)	($3.67)	$0.44	$1.33	($0.47)
AEP	($2.62)	($1.76)	($3.48)	$0.41	$1.40	($0.58)
AP	($2.72)	($1.92)	($3.52)	$0.25	$1.45	($0.96)
ATSI	($2.75)	($1.85)	($3.70)	$0.33	$1.35	($0.72)
BGE	($2.77)	($2.14)	($3.41)	$0.60	$1.62	($0.43)
ComEd	($2.58)	($1.67)	($3.53)	$0.46	$1.11	($0.22)
DAY	($2.75)	($1.82)	($3.72)	$0.45	$1.39	($0.53)
DEOK	($2.63)	($1.68)	($3.60)	$0.43	$1.25	($0.40)
DLCO	($2.67)	($1.82)	($3.56)	$0.29	$1.08	($0.53)
DPL	($2.89)	($1.97)	($3.79)	$0.47	$1.36	($0.41)
Dominion	($2.69)	($2.02)	($3.32)	$0.12	$1.20	($0.94)
EKPC	NA	NA	NA	$0.67	$1.65	($0.26)
JCPL	($3.50)	($3.33)	($3.68)	$0.37	$1.25	($0.60)
Met-Ed	($2.90)	($2.24)	($3.59)	$0.60	$1.61	($0.45)
PECO	($2.84)	($2.02)	($3.69)	$0.60	$1.65	($0.49)
PENELEC	($2.70)	($1.80)	($3.65)	$0.35	$1.51	($0.85)
Pepco	($2.74)	($2.11)	($3.39)	$0.61	$1.72	($0.54)
PPL	($2.99)	($2.34)	($3.65)	$0.35	$1.33	($0.67)
PSEG	($2.81)	($2.03)	($3.67)	$0.48	$1.55	($0.67)
RECO	($2.78)	($1.90)	($3.76)	$0.47	$1.60	($0.79)

Table 3-58 Day-ahead, average, zonal markup component (Adjusted): January through March of 2013 and 2014

	2013 (Jan - Mar)			2014 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($2.10)	($1.57)	($2.65)	$0.72	$1.45	($0.03)
AEP	($1.77)	($1.08)	($2.45)	$0.79	$1.63	($0.05)
AP	($1.85)	($1.24)	($2.46)	$0.59	$1.63	($0.46)
ATSI	($1.85)	($1.14)	($2.60)	$0.70	$1.56	($0.18)
BGE	($1.99)	($1.57)	($2.42)	$0.91	$1.74	$0.06
ComEd	($1.75)	($1.02)	($2.53)	$0.88	$1.41	$0.34
DAY	($1.87)	($1.12)	($2.64)	$0.83	$1.63	($0.00)
DEOK	($1.78)	($1.02)	($2.54)	$0.76	$1.44	$0.08
DLCO	($1.79)	($1.13)	($2.49)	$0.67	$1.27	$0.04
DPL	($2.03)	($1.31)	($2.73)	$0.76	$1.51	$0.01
Dominion	($1.89)	($1.40)	($2.36)	$0.43	$1.35	($0.47)
EKPC	NA	NA	NA	$1.00	$1.84	$0.21
JCPL	($2.46)	($2.26)	($2.67)	$0.68	$1.47	($0.17)
Met-Ed	($2.08)	($1.59)	($2.59)	$0.87	$1.74	($0.02)
PECO	($2.01)	($1.37)	($2.67)	$0.88	$1.77	($0.05)
PENELEC	($1.82)	($1.11)	($2.58)	$0.70	$1.70	($0.34)
Pepco	($1.97)	($1.54)	($2.42)	$0.90	$1.83	($0.06)
PPL	($2.14)	($1.64)	($2.65)	$0.64	$1.50	($0.24)
PSEG	($1.96)	($1.36)	($2.63)	$0.73	$1.64	($0.26)
RECO	($1.97)	($1.30)	($2.73)	$0.69	$1.65	($0.37)

Markup by Day-Ahead Price Levels

Table 3-59 and Table 3-60 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. The Table 3-59 shows that the average day-ahead markup increased significantly when day-ahead price is greater or equal to $150 from the first three months of 2013 to the first three months of 2014. There were zero hours when generating resources were marginal in this category in the first three months of 2013. However, there were 201 hours when generating resources were marginal in this category in the first three months of 2014. The highest average markup was $437.10 in hour ending 1400 on January 28.

Table 3-59 Average, day-ahead markup (By LMP category, unadjusted): January through March of 2013 and 2014

	2013 (Jan - Mar)		2014 (Jan - Mar)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($2.14)	3.1%	$0.00	0.0%
$25 to $50	($3.84)	90.7%	($1.83)	47.3%
$50 to $75	$1.78	5.5%	$0.33	26.2%
$75 to $100	$0.55	0.5%	($1.46)	8.0%
$100 to $125	$0.02	0.2%	($7.36)	3.5%
$125 to $150	$0.00	0.0%	$1.89	2.8%
>= $150	$0.00	0.0%	$10.31	12.3%

Table 3-60 Average, day-ahead markup (By LMP category, adjusted): January through March of 2013 and 2014

	2013 (Jan - Mar)		2014 (Jan - Mar)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($1.00)	3.1%	$0.00	0.0%
$25 to $50	($2.73)	90.7%	($1.09)	47.3%
$50 to $75	$1.95	5.5%	$0.62	26.2%
$75 to $100	$0.78	0.5%	($1.32)	8.0%
$100 to $125	($0.09)	0.2%	($7.25)	3.5%
$125 to $150	$0.00	0.0%	$2.13	2.8%
>= $150	$0.00	0.0%	$10.68	12.3%

Prices

The conduct of individual market entities within a market structure is reflected in market prices.[60] 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 148.5 percent and 154.9 percent higher in the first three months of 2014 than in the first three months of 2013 as a result of higher fuel costs and higher demand.[61] Natural gas prices were higher, particularly in eastern zones, while coal prices were relatively constant.

PJM real-time energy market prices increased in the first three months of 2014 compared to the first three months of 2013. The system average LMP was 131.3 percent higher in the first three months of 2014 than in the first three months of 2013, $84.04 per MWh versus $36.33 per MWh. The load-weighted average LMP was 148.5 percent higher in the first three months of 2014 than in the first three months of 2013, $92.98 per MWh versus $37.41 per MWh.

The fuel-cost adjusted, load-weighted, average LMP for the first three months of 2014 was 24.1 percent lower than the load-weighted, average LMP for the first three months of 2014. If fuel costs in the first three months of 2014 had been the same as in the first three months of 2013, holding everything else constant, the load-weighted LMP would have been lower, $70.59 per MWh instead of the observed $92.98 per MWh in the first three months of 2014.

PJM day-ahead energy market prices increased in the first three months of 2014 compared to the first three months of 2013. The system average LMP was 137.3 percent higher in the first three months of 2014 than in the first three months of 2013, $86.52 per MWh versus $36.46 per MWh. The load-weighted

60 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>.

61 There was an average increase of 4.9 heating degree days and no change in cooling degree days in the first three months of 2014 compared to the first three months of 2013, which meant overall increased demand.

average LMP was 154.9 percent higher in the first three months of 2014 than in the first three months of 2013, $94.97 per MWh versus $37.26 per MWh.[62]

Real-Time LMP

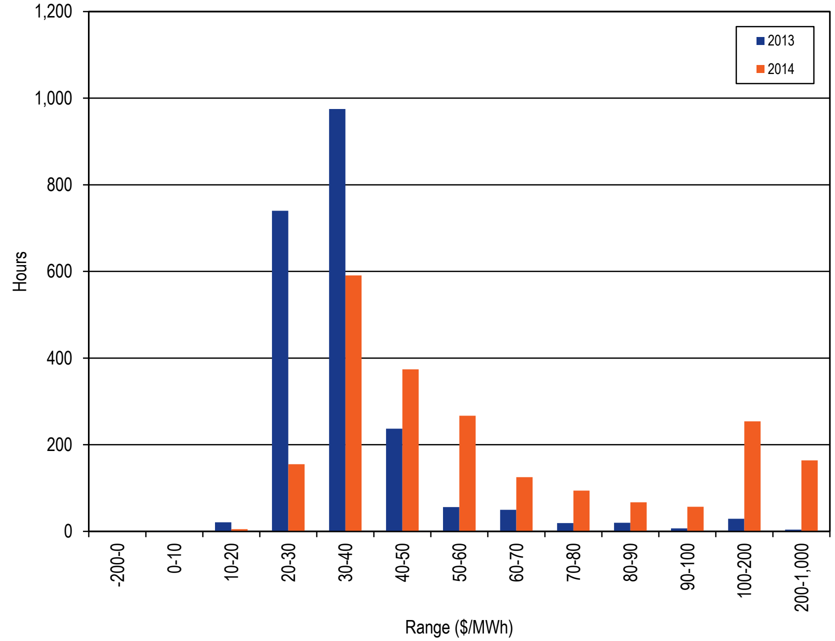
Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[63]

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 3-25 shows the hourly distribution of PJM real-time average LMP for the first three months of 2013 and the first three months of 2014. There were no hours in the first three months of 2013 and 2014 where the real-time LMP for the entire system was negative. 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. There were no hours in the first three months of 2013 and 2014 where the PJM real-time LMP was $0.00.

Figure 3-25 Average LMP for the PJM Real-Time Energy Market: January through March of 2013 and 2014



62 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."

63 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>.

PJM Real-Time, Average LMP

Table 3-61 shows the PJM real-time, average LMP for the first three months of each year of the 17-year period 1998 to 2014.[64]

Table 3-61 PJM real-time, average LMP (Dollars per MWh): January through March of 1998 through 2014

	Real-Time LMP			Year-to-Year Change		
Jan-Mar	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$17.51	$15.30	$7.84	NA	NA	NA
1999	$18.79	$16.56	$7.29	7.3%	8.3%	(7.0%)
2000	$23.66	$17.73	$16.22	25.9%	7.0%	122.4%
2001	$33.77	$26.01	$20.79	42.8%	46.8%	28.2%
2002	$22.23	$19.22	$9.61	(34.2%)	(26.1%)	(53.8%)
2003	$49.57	$43.08	$30.54	123.0%	124.2%	217.9%
2004	$46.37	$41.04	$24.07	(6.5%)	(4.8%)	(21.2%)
2005	$46.51	$40.62	$22.07	0.3%	(1.0%)	(8.3%)
2006	$52.98	$46.15	$23.29	13.9%	13.6%	5.5%
2007	$55.34	$47.15	$33.29	4.5%	2.2%	43.0%
2008	$66.75	$57.05	$35.54	20.6%	21.0%	6.8%
2009	$47.29	$40.56	$21.99	(29.2%)	(28.9%)	(38.1%)
2010	$44.13	$37.82	$21.87	(6.7%)	(6.8%)	(0.6%)
2011	$44.76	$38.14	$23.10	1.4%	0.8%	5.6%
2012	$30.38	$28.82	$11.63	(32.1%)	(24.4%)	(49.7%)
2013	$36.33	$32.29	$18.47	19.6%	12.1%	58.9%
2014	$84.04	$48.77	$119.84	131.3%	51.0%	548.8%

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 3-62 shows the PJM real-time, load-weighted, average LMP for the first three months of each year of the 17-year period 1998 to 2014.

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

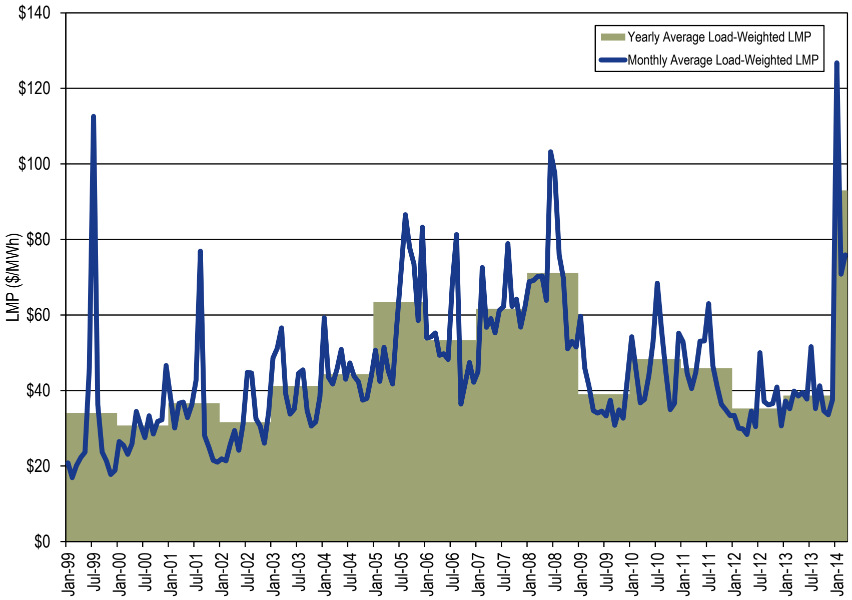
Table 3-62 PJM real-time, load-weighted, average LMP (Dollars per MWh): January through March of 1998 through 2014

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
Jan-Mar	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$18.13	$15.80	$8.14	NA	NA	NA
1999	$19.38	$16.90	$7.66	6.9%	7.0%	(5.9%)
2000	$25.10	$18.25	$17.22	29.5%	8.0%	124.9%
2001	$35.16	$27.38	$21.52	40.1%	50.0%	25.0%
2002	$23.01	$19.89	$9.93	(34.6%)	(27.4%)	(53.8%)
2003	$51.93	$46.12	$30.99	125.6%	131.9%	211.9%
2004	$48.77	$43.22	$24.62	(6.1%)	(6.3%)	(20.6%)
2005	$48.37	$42.20	$22.62	(0.8%)	(2.4%)	(8.1%)
2006	$54.43	$47.62	$23.69	12.5%	12.9%	4.7%
2007	$58.07	$50.60	$34.44	6.7%	6.3%	45.4%
2008	$69.35	$60.11	$36.56	19.4%	18.8%	6.2%
2009	$49.60	$42.23	$23.38	(28.5%)	(29.8%)	(36.1%)
2010	$45.92	$39.01	$22.99	(7.4%)	(7.6%)	(1.7%)
2011	$46.35	$39.11	$24.26	0.9%	0.3%	5.5%
2012	$31.21	$29.25	$12.02	(32.7%)	(25.2%)	(50.5%)
2013	$37.41	$32.79	$19.90	19.9%	12.1%	65.7%
2014	$92.98	$51.62	$134.40	148.5%	57.4%	575.3%

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

Figure 3-26 shows the PJM real-time monthly and annual load-weighted LMP from 1999 through the first three months of 2014.

Figure 3-26 PJM real-time, monthly and annual, load-weighted, average LMP: 1999 through March of 2014



Fuel Price Trends and LMP

Changes in LMP can result from changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of marginal cost depending on generating technology, unit efficiency, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs. Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. Natural gas, especially in the eastern part of PJM increased in price in the first quarter of 2014. Comparing fuel prices in the first quarter of 2014 to the first quarter of 2013, the price of Northern Appalachian coal was 3.7 percent higher; the price of Central Appalachian coal was 4.6 percent lower; the price of Powder River Basin coal was 8.3 percent higher; the price of eastern natural gas was 160.2 percent higher; and the price of western natural gas was 81.1 percent higher. Figure 3-27 shows monthly average spot fuel prices for the first quarter of 2013 and the first quarter of 2014.[65] Natural gas prices were above coal prices in the first quarter of 2014.

Figure 3-27 Spot average fuel price comparison with fuel delivery charges: 2012 through 2014 ($/MMBtu)

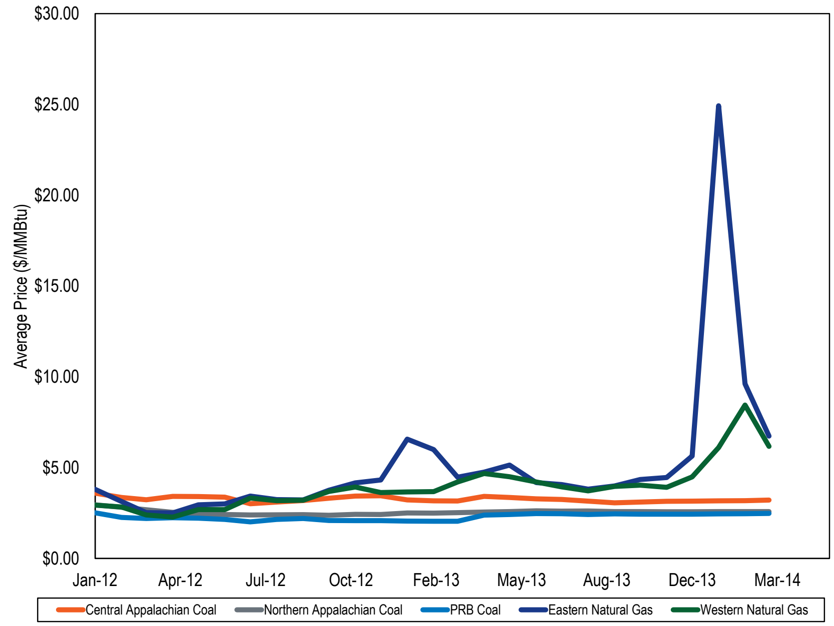


Table 3-63 compares the first three months of 2014 PJM real time fuel-cost adjusted, load-weighted, average LMP to the first three months of 2012 load-weighted, average LMP. The real time fuel-cost adjusted, load-weighted, average LMP for the first three months of 2014 was 24.1 percent lower than the real time load-weighted, average LMP for the first three months of 2014. The real-time, fuel-cost adjusted, load-weighted, average LMP for the first three months of 2014 was 88.7 percent higher than the real time load-

65 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.

weighted LMP for the first three months of 2013. If fuel costs in the first three months of 2014 had been the same as in the first three months of 2013, holding everything else constant, the first three months of 2014 real time load-weighted LMP would have been lower, $70.59 per MWh instead of the observed $92.88 per MWh.

Table 3-63 PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): Year-over-year method

	2014 Load-Weighted LMP	2014 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$92.98	$70.59	(24.1%)
	2013 Load-Weighted LMP	2014 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$37.41	$70.59	88.7%
	2013 Load-Weighted LMP	2014 Load-Weighted LMP	Change
Average	$37.41	$92.98	148.5%

Table 3-64 shows the impact of each fuel type on the difference between the first three months of 2014 fuel-cost adjusted, load-weighted average LMP and the first three months of 2014 load-weighted LMP. Table 3-64 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 the first three months of 2014.

Table 3-64 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	$0.60	2.7%
Gas	$21.66	96.8%
Oil	$0.12	0.5%
Uranium	$0.01	0.0%
Wind	($0.00)	(0.0%)
Total	$22.39	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 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.[66] 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.

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 3-65, including markup using unadjusted cost offers.[67] Table 3-65 shows that for the first three months of 2014, 20.8 percent of the load-weighted LMP was the result of coal costs, 40.2 percent was the result of gas costs and 1.05 percent was the result of the cost of emission allowances. Markup was $5.52 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

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

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

effect of excluding those five-minute intervals is the component NA. In the first three months of 2014, nearly nine 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 the first three months of 2014 and the first three months of 2013.

Table 3-65 Components of PJM real-time (Unadjusted), annual, load-weighted, average LMP: January through March, 2013 and 2014

	2013 (Jan - Mar)		2014 (Jan - Mar)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$10.77	28.8%	$37.41	40.2%	11.4%
Coal	$20.20	54.0%	$19.37	20.8%	(33.1%)
Increase Generation Adder	$0.11	0.3%	$8.11	8.7%	8.4%
Emergency DR Adder	$0.00	0.0%	$6.70	7.2%	7.2%
Ten Percent Adder	$3.71	9.9%	$6.60	7.1%	(2.8%)
Markup	($1.64)	(4.4%)	$5.52	5.9%	10.3%
FMU Adder	$0.40	1.1%	$5.15	5.5%	4.5%
NA	$0.54	1.5%	$4.49	4.8%	3.4%
Oil	$0.28	0.7%	$3.72	4.0%	3.3%
VOM	$2.23	6.0%	$2.66	2.9%	(3.1%)
CO_2 Cost	$0.06	0.2%	$0.84	0.9%	0.7%
LPA Rounding Difference	$0.43	1.2%	$0.32	0.3%	(0.8%)
NO_x Cost	$0.09	0.2%	$0.12	0.1%	(0.1%)
SO_2 Cost	$0.01	0.0%	$0.01	0.0%	(0.0%)
Other	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Uranium	$0.00	0.0%	($0.02)	(0.0%)	(0.0%)
Wind	$0.00	0.0%	($0.02)	(0.0%)	(0.0%)
Market-to-Market Adder	($0.00)	(0.0%)	($0.03)	(0.0%)	(0.0%)
Decrease Generation Adder	($0.11)	(0.3%)	($0.48)	(0.5%)	(0.2%)
Ancillary Service Redispatch cost	$0.41	1.1%	($1.06)	(1.1%)	(2.2%)
LPA-SCED Differential	($0.07)	(0.2%)	($6.44)	(6.9%)	(6.7%)
Total	$37.41	100.0%	$92.98	100.0%	0.0%

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 3-65 and Table 3-69) markup is simply the difference between the price offer and the cost offer. In the second approach, (Table 3-66 and Table 3-70) the 10 percent markup is removed from the cost offers of coal units.

The components of LMP are shown in Table 3-66, including markup using adjusted cost offers.

Table 3-66 Components of PJM real-time (Adjusted), annual, load-weighted, average LMP: January through March, 2013 and 2014

	2013 (Jan - Mar)		2014 (Jan - Mar)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$10.77	28.8%	$37.41	40.2%	11.4%
Coal	$20.43	54.6%	$21.42	23.0%	(31.6%)
Increase Generation Adder	$0.11	0.3%	$8.11	8.7%	8.4%
Markup	$0.13	0.3%	$7.12	7.7%	7.3%
Emergency Demand Response Adder	$0.00	0.0%	$6.70	7.2%	7.2%
Ten Percent Adder	$1.78	4.8%	$5.36	5.8%	1.0%
NA	$0.54	1.5%	$4.49	4.8%	3.4%
Oil	$0.28	0.7%	$3.72	4.0%	3.3%
VOM	$2.25	6.0%	$2.91	3.1%	(2.9%)
FMU Adder	$0.29	0.8%	$2.43	2.6%	1.8%
CO_2 Cost	$0.06	0.2%	$0.88	0.9%	0.8%
LPA Rounding Difference	$0.43	1.2%	$0.32	0.3%	(0.8%)
NO_x Cost	$0.09	0.2%	$0.13	0.1%	(0.1%)
SO_2 Cost	$0.01	0.0%	$0.02	0.0%	(0.0%)
Other	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Uranium	$0.00	0.0%	($0.02)	(0.0%)	(0.0%)
Wind	$0.00	0.0%	($0.02)	(0.0%)	(0.0%)
Market-to-Market Adder	($0.00)	(0.0%)	($0.03)	(0.0%)	(0.0%)
Decrease Generation Adder	($0.11)	(0.3%)	($0.48)	(0.5%)	(0.2%)
PSC_ADDER	$0.41	1.1%	($1.06)	(1.1%)	(2.2%)
LPA-SCED Differential	($0.07)	(0.2%)	($6.44)	(6.9%)	(6.7%)
Total	$37.41	100.0%	$92.98	100.0%	0.0%

Day-Ahead LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[68]

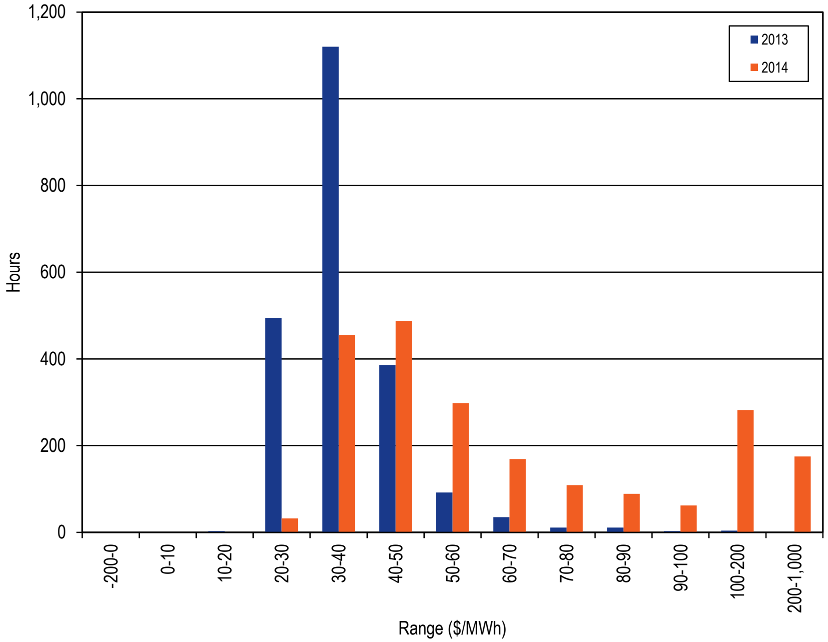
Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-28 shows the hourly distribution of PJM day-ahead average LMP for the first three months of 2013 and the first three months of 2014.

68 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>.

Figure 3-28 Average LMP for the PJM Day-Ahead Energy Market: January through March of 2013 and 2014



PJM Day-Ahead, Average LMP

Table 3-67 shows the PJM day-ahead, average LMP for the first three months of each year of the 14-year period 2001 to 2014.

Table 3-67 PJM day-ahead, average LMP (Dollars per MWh): January through March of 2001 through 2014

	Day-Ahead LMP			Year-to-Year Change		
Jan-Mar	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.45	$32.72	$16.39	NA	NA	NA
2002	$22.43	$20.59	$7.56	(38.5%)	(37.1%)	(53.9%)
2003	$51.20	$46.06	$25.65	128.2%	123.7%	239.3%
2004	$45.84	$43.01	$18.85	(10.5%)	(6.6%)	(26.5%)
2005	$45.14	$41.56	$16.19	(1.5%)	(3.4%)	(14.1%)
2006	$51.23	$48.53	$14.16	13.5%	16.8%	(12.6%)
2007	$52.76	$49.43	$22.59	3.0%	1.9%	59.5%
2008	$66.10	$62.57	$23.90	25.3%	26.6%	5.8%
2009	$47.41	$43.43	$16.85	(28.3%)	(30.6%)	(29.5%)
2010	$46.13	$41.99	$15.93	(2.7%)	(3.3%)	(5.5%)
2011	$45.60	$41.10	$16.82	(1.2%)	(2.1%)	5.6%
2012	$30.82	$30.04	$6.63	(32.4%)	(26.9%)	(60.6%)
2013	$36.46	$34.45	$9.78	18.3%	14.7%	47.5%
2014	$86.52	$52.80	$92.80	137.3%	53.3%	848.8%

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 3-68 shows the PJM day-ahead, load-weighted, average LMP for the first three months of each year of the 14-year period 2001 to 2014.

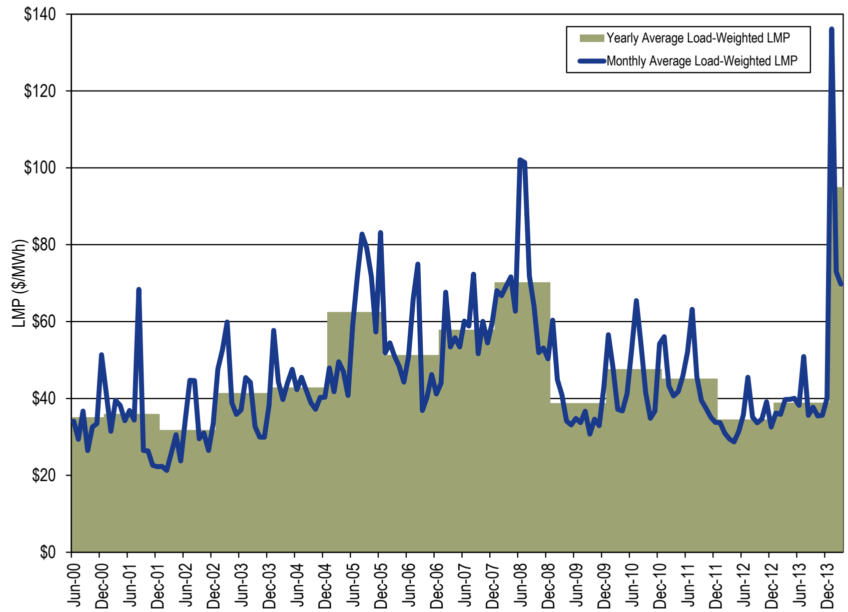
Table 3-68 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through March of 2001 through 2014

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
Jan-Mar	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$37.70	$34.55	$16.66	NA	NA	NA
2002	$23.17	$21.18	$7.76	(38.5%)	(38.7%)	(53.4%)
2003	$53.16	$48.69	$25.75	129.5%	129.9%	231.7%
2004	$47.75	$45.02	$19.19	(10.2%)	(7.5%)	(25.4%)
2005	$46.54	$42.88	$16.46	(2.5%)	(4.8%)	(14.2%)
2006	$52.40	$49.51	$14.29	12.6%	15.5%	(13.2%)
2007	$54.87	$51.89	$23.16	4.7%	4.8%	62.0%
2008	$68.00	$64.70	$24.35	23.9%	24.7%	5.1%
2009	$49.44	$44.85	$17.54	(27.3%)	(30.7%)	(28.0%)
2010	$47.77	$43.62	$16.52	(3.4%)	(2.7%)	(5.8%)
2011	$47.14	$42.49	$17.73	(1.3%)	(2.6%)	7.3%
2012	$31.51	$30.44	$6.83	(33.2%)	(28.3%)	(61.5%)
2013	$37.26	$35.02	$10.26	18.3%	15.0%	50.3%
2014	$94.97	$56.53	$102.23	154.9%	61.4%	896.7%

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

Figure 3-29 shows the PJM day-ahead, monthly and annual, load-weighted LMP from 2000 through the first three months of 2014.[69]

Figure 3-29 Day-ahead, monthly and annual, load-weighted, average LMP: 2000 through March of 2014



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

69 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.

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 in RGGI, Delaware and Maryland.[70] 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 3-69, including markup using unadjusted cost offers. Table 3-69 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In the first quarter of 2014, 26.5 percent of the load-weighted LMP was the result of gas, 20.0 percent was the result of the cost of up-to congestion transactions and 13.2 percent was the result of the cost of INC.

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

Table 3-69 Components of PJM day-ahead, (unadjusted) annual, load-weighted, average LMP (Dollars per MWh): January through March of 2013 and 2014[71]

	2013 (Jan - Mar)		2014 (Jan - Mar)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$7.22	19.4%	$25.14	26.5%	7.1%
Up-to Congestion Transaction	$3.09	8.3%	$18.97	20.0%	11.7%
INC	$3.23	8.7%	$12.56	13.2%	4.6%
DEC	$5.57	14.9%	$12.27	12.9%	(2.0%)
Dispatchable Transaction	$0.43	1.2%	$7.31	7.7%	6.5%
Coal	$15.46	41.5%	$6.77	7.1%	(34.4%)
Ten Percent Cost Adder	$2.45	6.6%	$3.48	3.7%	(2.9%)
Price Sensitive Demand	$0.18	0.5%	$2.79	2.9%	2.4%
FMU Adder	$0.13	0.4%	$2.37	2.5%	2.1%
VOM	$1.69	4.5%	$1.20	1.3%	(3.3%)
Oil	$0.01	0.0%	$0.96	1.0%	1.0%
Import	$0.00	0.0%	$0.55	0.6%	0.6%
Markup	($2.74)	(7.4%)	$0.39	0.4%	7.8%
DASR Offer Adder	$0.00	0.0%	$0.18	0.2%	0.2%
CO_2	$0.04	0.1%	$0.09	0.1%	(0.0%)
Diesel	$0.00	0.0%	$0.05	0.0%	0.0%
NO_x	$0.06	0.2%	$0.04	0.0%	(0.1%)
Constrained Off	$0.00	0.0%	$0.01	0.0%	0.0%
SO_2	$0.01	0.0%	$0.00	0.0%	(0.0%)
Wind	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
DASR LOC Adder	$0.00	0.0%	($0.11)	(0.1%)	(0.1%)
NA	$0.42	1.1%	($0.03)	(0.0%)	(1.2%)
Total	$37.26	100.0%	$94.97	100.0%	0.0%

Table 3-70 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.

71 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 3-70 Components of PJM day-ahead, (adjusted) annual, load-weighted, average LMP (Dollars per MWh): January through March of 2013 and 2014

	2013 (Jan - Mar)		2014 (Jan - Mar)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$7.22	19.4%	$25.14	26.5%	7.1%
Up-to Congestion Transaction	$3.09	8.3%	$18.97	20.0%	11.7%
INC	$3.23	8.7%	$12.56	13.2%	4.6%
DEC	$5.57	14.9%	$12.27	12.9%	(2.0%)
Dispatchable Transaction	$0.43	1.2%	$7.31	7.7%	6.5%
Coal	$15.46	41.5%	$6.74	7.1%	(34.4%)
Ten Percent Cost Adder	$1.60	4.3%	$3.17	3.3%	(1.0%)
Price Sensitive Demand	$0.18	0.5%	$2.79	2.9%	2.4%
FMU Adder	$0.13	0.4%	$2.37	2.5%	2.1%
VOM	$1.69	4.5%	$1.19	1.3%	(3.3%)
Oil	$0.01	0.0%	$0.96	1.0%	1.0%
Markup	($1.89)	(5.1%)	$0.73	0.8%	5.8%
Import	$0.00	0.0%	$0.55	0.6%	0.6%
DASR Offer Adder	$0.00	0.0%	$0.18	0.2%	0.2%
CO_2	$0.04	0.1%	$0.09	0.1%	(0.0%)
Diesel	$0.00	0.0%	$0.05	0.0%	0.0%
NO_x	$0.06	0.2%	$0.04	0.0%	(0.1%)
Constrained Off	$0.00	0.0%	$0.01	0.0%	0.0%
SO_2	$0.01	0.0%	$0.00	0.0%	(0.0%)
Wind	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
DASR LOC Adder	$0.00	0.0%	($0.11)	(0.1%)	(0.1%)
NA	$0.42	1.1%	($0.03)	(0.0%)	(1.2%)
Total	$37.26	100.0%	$94.97	100.0%	0.0%

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 3-71 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 the first three months of 2013 and the first three months of 2014. In the first three months of 2014, 55.4 percent of all cleared UTC transactions were net profitable, with 67.0 percent of the source side profitable and 34.3 percent of the sink side profitable (Table 3-71).

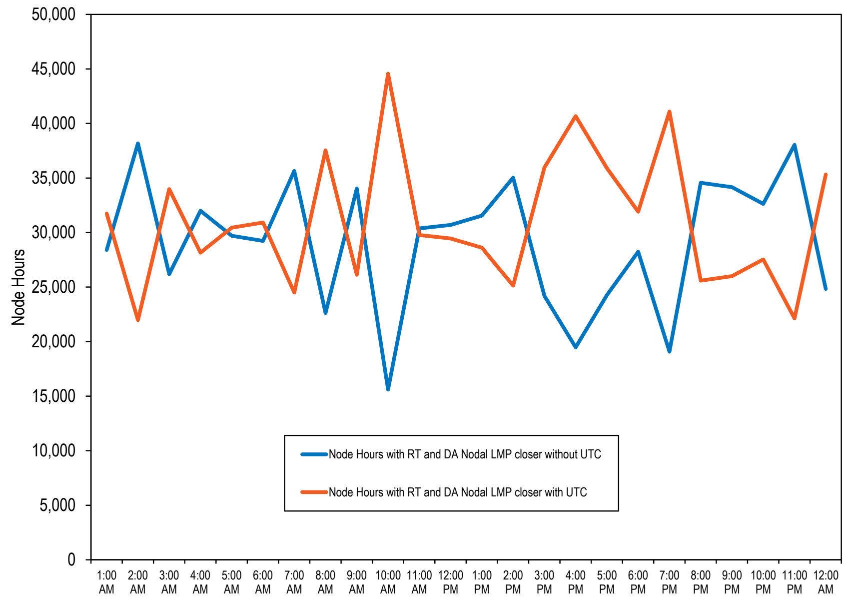
Table 3-71 Cleared UTC profitability by source and sink point: January through March of 2013 and 2014[72]

Jan-Mar	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	Profitable UTC	Profitable Source	Profitable Sink
2013	3,073,376	1,657,702	2,045,964	1,050,641	53.9%	66.6%	34.2%
2014	6,624,360	3,672,069	4,441,271	2,274,067	55.4%	67.0%	34.3%

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.[73] The MMU used PJM's results from the May Study to analyze the effects of UTCs on price convergence.

Figure 3-30 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.

Figure 3-30 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



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

72 Calculations exclude PJM administrative charges.
73 ALSTOM SPD program and unit commitment process.

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 3-32).

Table 3-72 shows that the difference between the average real-time price and the average day-ahead price was -$0.13 per MWh in the first three months of 2013 and -$2.48 per MWh in the first three months of 2014. The difference between average on-peak real-time price and the average day-ahead price was $0.47 per MWh in the first three months of 2013 and -$4.81 per MWh in the first three months of 2014.

Table 3-72 Day-ahead and real-time average LMP (Dollars per MWh): January through March of 2013 and 2014[74]

	2013 (Jan-Mar)				2014 (Jan-Mar)			
	Day Ahead	Real Time	Difference	Percent of Real Time	Day Ahead	Real Time	Difference	Percent of Real Time
Average	$36.46	$36.33	($0.13)	(0.4%)	$86.52	$84.04	($2.48)	(2.9%)
Median	$34.45	$32.29	($2.16)	(6.7%)	$52.80	$48.77	($4.04)	(8.3%)
Standard deviation	$9.78	$18.47	$8.69	47.0%	$92.80	$119.84	$27.03	22.6%
Peak average	$40.55	$41.02	$0.47	1.1%	$109.96	$105.15	($4.81)	(4.6%)
Peak median	$37.86	$35.02	($2.84)	(8.1%)	$69.23	$58.80	($10.43)	(17.7%)
Peak standard deviation	$10.81	$22.56	$11.75	52.1%	$114.90	$150.94	$36.04	23.9%
Off peak average	$32.87	$32.22	($0.65)	(2.0%)	$65.99	$65.56	($0.44)	(0.7%)
Off peak median	$31.64	$29.82	($1.82)	(6.1%)	$45.28	$41.35	($3.92)	(9.5%)
Off peak standard deviation	$7.05	$12.59	$5.54	44.0%	$60.80	$79.15	$18.35	23.2%

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 3-73 shows the difference between the Real-Time and the Day-Ahead Energy Market prices for the first three months of each year of the 14-year period 2001 to 2014.

Table 3-73 Day-ahead and real-time average LMP (Dollars per MWh): January through March of 2001 through 2014

Jan-Mar	Day Ahead	Real Time	Difference	Percent of Real Time
2001	$36.45	$33.77	($2.68)	(7.3%)
2002	$22.43	$22.23	($0.20)	(0.9%)
2003	$51.20	$49.57	($1.63)	(3.2%)
2004	$45.84	$46.37	$0.52	1.1%
2005	$45.14	$46.51	$1.37	3.0%
2006	$51.23	$52.98	$1.75	3.4%
2007	$52.76	$55.34	$2.58	4.9%
2008	$66.10	$66.75	$0.65	1.0%
2009	$47.41	$47.29	($0.12)	(0.2%)
2010	$46.13	$44.13	($2.00)	(4.3%)
2011	$45.60	$44.76	($0.84)	(1.8%)
2012	$30.82	$30.38	($0.43)	(1.4%)
2013	$36.46	$36.33	($0.13)	(0.4%)
2014	$86.52	$84.04	($2.48)	(2.9%)

Table 3-74 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for the first three months of 2007 through 2014.

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

Table 3-74 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): January through March of 2007 through 2014

	2007		2008		2009		2010		2011		2012		2013		2014	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($1,000) to ($750)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	2	0.09%
($750) to ($500)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	3	0.23%
($500) to ($450)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.28%
($450) to ($400)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	6	0.56%
($400) to ($350)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	5	0.79%
($350) to ($300)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	5	1.02%
($300) to ($250)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	6	1.30%
($250) to ($200)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	14	1.95%
($200) to ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	14	2.59%
($150) to ($100)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.05%	0	0.00%	0	0.00%	45	4.68%
($100) to ($50)	14	0.65%	21	0.96%	1	0.05%	5	0.23%	17	0.83%	2	0.09%	0	0.00%	88	8.75%
($50) to $0	1,214	56.88%	1,309	60.93%	1,347	62.44%	1,569	72.90%	1,464	68.64%	1,566	71.83%	1,542	71.42%	1,242	66.28%
$0 to $50	847	96.11%	740	94.82%	788	98.93%	547	98.24%	619	97.31%	601	99.36%	587	98.61%	595	93.84%
$50 to $100	73	99.49%	97	99.27%	21	99.91%	33	99.77%	51	99.68%	12	99.91%	23	99.68%	55	96.39%
$100 to $150	7	99.81%	14	99.91%	2	100.00%	1	99.81%	6	99.95%	2	100.00%	3	99.81%	27	97.64%
$150 to $200	0	99.81%	1	99.95%	0	100.00%	4	100.00%	1	100.00%	0	100.00%	3	99.95%	16	98.38%
$200 to $250	1	99.86%	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	9	98.80%
$250 to $300	1	99.91%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	100.00%	8	99.17%
$300 to $350	2	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	2	99.26%
$350 to $400	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	99.40%
$400 to $450	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	99.44%
$450 to $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.44%
$500 to $750	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	7	99.77%
$750 to $1,000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.77%
$1,000 to $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	99.81%
>= $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	4	100.00%

Figure 3-31 shows the hourly differences between day-ahead and real-time hourly LMP in the first three months of 2014.

Figure 3-32 shows the monthly average differences between the day-ahead and real-time LMP in the first three months of 2014.

Figure 3-31 Real-time hourly LMP minus day-ahead hourly LMP: January through March of 2014

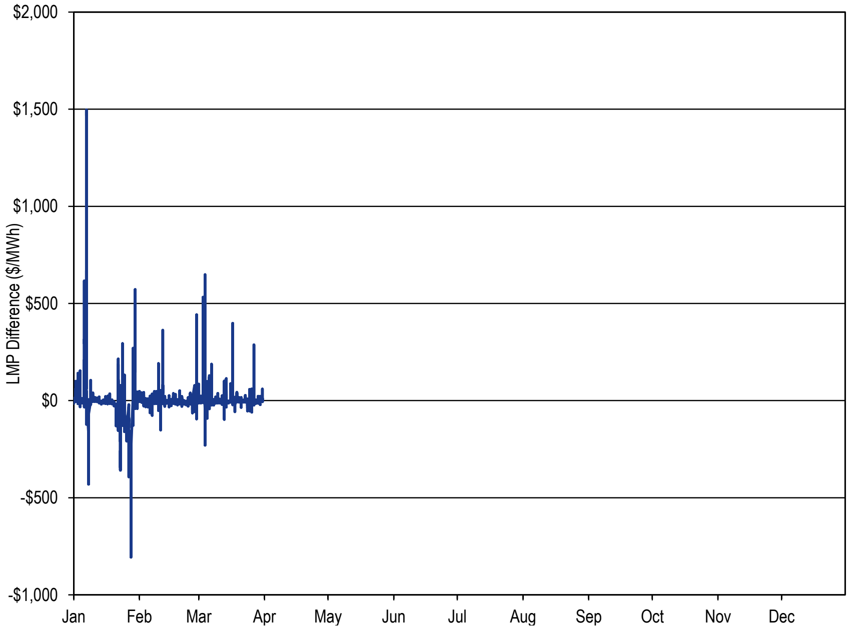


Figure 3-32 Monthly average of real-time minus day-ahead LMP: January through March of 2014

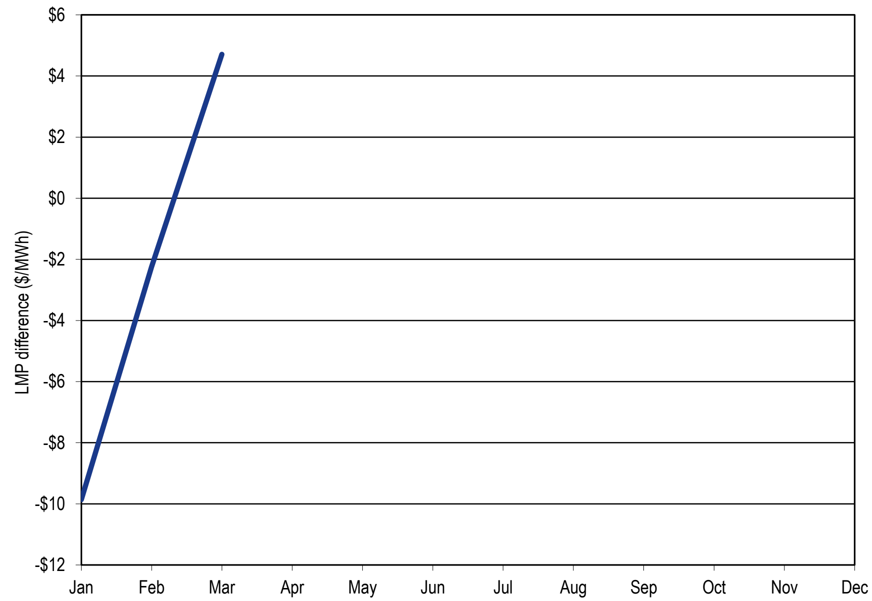
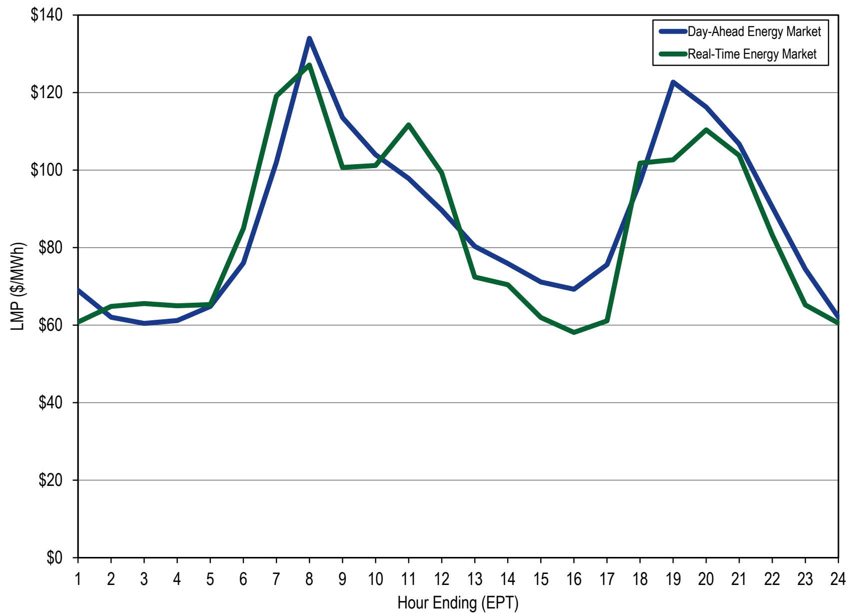


Figure 3-33 shows day-ahead and real-time LMP on an average hourly basis for the first three months of 2014.

Figure 3-33 PJM system hourly average LMP: January through March of 2014



Scarcity

PJM's Energy Market experienced shortage pricing events on two days in January 2014. Extreme cold weather conditions in January resulted in record winter peak loads. The high demand combined with high forced outage rates, and supply interruptions for natural gas fueled generation resulted in low reserve margins and associated shortage pricing events, and high uplift payments in January. Table 3-75 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in the first three months of 2013 and 2014. The only emergency alerts declared in the first three months of 2013 were cold weather alerts.

Table 3-75 Summary of emergency events declared in the first three months of 2013 and 2014

	Number of days events declared	
Event Type	Jan - Mar, 2013	Jan - Mar, 2014
Cold Weather Alert	4	25
Maximum Emergency Generation Alert	0	6
Primary Reserve Alert	0	2
Voltage Reduction Alert	0	2
Primary Reserve Warning	0	1
Voltage Reduction Warning	0	4
Emergency Load Management Long Lead Time	0	6
Emergency Load Management Short Lead Time	0	6
Maximum Emergency Action	0	8
Emergency Energy Bids Requested	0	3
Voltage Reduction Action	0	1
Shortage Pricing	0	2

This section addresses issues related to the emergency operations and extreme weather events in the PJM service territory in the first three months of 2014.

Emergency procedures

PJM declared cold weather alerts on 25 days in the first three months of 2014 compared to only four days in the first three months of 2013.[75] 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 six days in the first three months of 2014. 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 actions. It is called to alert PJM members that maximum emergency generation may be requested in the operating capacity.[76] This means that if PJM directs members to load maximum emergency generation during the operating day, the resources must

75 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), Section 3.3 Cold Weather Alert, p. 41.
76 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), Section 2.3.1 Day-Ahead Emergency Procedures: Alerts, p. 16.

be able to increase generation above the maximum economic level of their offer.

PJM declared a primary reserve alert on two days in the first three months of 2014. The purpose of a primary reserve alert is to alert members at least one day prior to the operating day that available primary reserves are anticipated to be short of the primary reserve requirement on the operating day. It is issued when the estimated primary reserves are less than the forecast primary reserve requirement.

PJM declared a voltage reduction alert on two days in the first three months of 2014. The purpose of a voltage reduction alert is to alert members at least one day prior to the operating day that a voltage reduction may be required on the operating day. It is issued when the estimated operating reserve is less than the forecast synchronized reserve requirement.

PJM declared a primary reserve warning on one day in the first three months of 2014. The purpose of a primary reserve warning is to warn members that available primary reserves are less than the primary reserve requirement but greater than the synchronized reserve requirement.

PJM declared a voltage reduction warning and reduction of non-critical plant load on four days in the first three months of 2014. The purpose of a voltage reduction warning and reduction of non-critical plant load is to warn members that available synchronized reserves are less than the synchronized reserve requirement and that a voltage reduction may be required. It can be issued for the RTO or for specific control zones.

PJM declared emergency mandatory load management reductions (long lead time and short lead time) in all or parts of the PJM service territory on six days in the first three months of 2014. The purpose of emergency mandatory load management 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 (long lead time) and a lead time of up to one hour (short lead time). Despite that the formal name of PJM's action, load reductions (both long lead time and short lead time) during the first three months of 2014 are voluntary and not mandatory, because they occurred outside of the mandatory summer compliance period of June 1 through September 30. Load reductions during these events are not counted for performance assessment.

PJM declared maximum emergency generation actions on eight days in the first three months of 2014. The purpose of a maximum emergency generation action is to request generators to increase output to the maximum emergency level which unit owners may define at a level above the maximum economic level. A maximum emergency generation action can be issued for the RTO, for specific control zones or for parts of control zones. Maximum emergency generation action was declared for the RTO on four days in the first three months of 2013 (January 6, 7, 8 and March 4); for the BGE and Pepco control zones on January 22; for the Mid-Atlantic and Dominion regions on January 23, 24 and 30; and for the AP zone on January 23 and 24.

PJM requested bids for emergency energy purchases on three days in the first three months of 2014. On January 7, PJM requested bids for emergency energy between 0600 and 1100 and again between hours 1700 to 2100. PJM also requested bids for emergency energy on January 8 and January 23, but did not purchase any emergency energy.

PJM did not recall energy from PJM capacity resources that were exporting energy during emergency conditions in the first three months of 2014.

PJM issued a voltage reduction action on one day (January 6) in the first three months of 2014. The purpose of a voltage reduction is to reduce load to provide sufficient reserves, to maintain tie flow schedules, and to preserve limited energy sources. When a voltage reduction action is issued for a reserve zone or sub-zone, the primary reserve penalty factor and synchronized reserve penalty factor are incorporated into the synchronized and non-synchronized reserve market clearing prices and locational marginal prices until the voltage reduction action has been terminated.

There were nineteen spinning events in the first three months of 2014 compared to four in the first three months of 2013.[77] Of the nineteen, ten were classified as system disturbances caused by unit trips. Of those ten system disturbances, seven occurred in January.

Table 3-76 provides a description of PJM declared emergency procedures.

Table 3-76 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.
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.
Primary Reserve Alert	To alert members of a projected shortage of primary reserve for a future period. It is implemented when estimated primary reserve is less than the forecast requirement.
Voltage Reduction Alert	To alert members thjat a voltage reduction may be required during a future critical period. It is implemented when estimated reserve capacity is less than forecasted synchronized reserve requirement.
Primary Reserve Warning	To warn members that available primary reserve is less than required and present operations are becoming critical. It is implemented when available primary reserve is less than the primary reserve requirement but greater than the synchronized reserve requirement.
Voltage Reduction Warning & Reduction of Non-Critical Plant Load	To warn members that actual synchronized reserves are less than the synchronized reserve requiremtn and that voltage reduction may be required.
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	To reduce load to provide sufficient reserve capacity to maintain tie flow schedules and preserve limited energy sources. It is implemented when load relief is needed to maintain tie schedules.

77 See *2014 Quarterly State of the Market Report for PJM: January through March*, Section 10: Ancillary Service Markets for details on the spinning events.

Table 3-77 shows the dates on which emergency alerts and warnings were declared as well as emergency actions were implemented in the first three months of 2014.

Table 3-77 PJM declared emergency alerts, warnings and actions: January through March, 2014

Dates	Cold Weather Alert	Maximum Emergency Generation Alert	Primary Reserve Alert	Voltage Reduction Alert	Primary Reserve Warning	Voltage Reduction Warning and Reduction of Non-Critical Plant Load	Maximum Emergency Generation Action	Emergency Load Management Long Lead Time	Emergency Load Management Short Lead Time	Voltage Reduction
1/1/2014	ComEd									
1/2/2014	ComEd									
1/3/2014	PJM except Southern region									
1/6/2014	PJM except Mid-Atlantic and Dominion					PJM	PJM			PJM
1/7/2014	PJM	PJM			PJM	PJM	PJM	PJM	PJM	
1/8/2014	PJM	PJM					PJM	PJM	PJM	
1/21/2014	PJM except Mid-Atlantic and Dominion									
1/22/2014	PJM						BGE, Pepco	BGE, Pepco	BGE, Pepco	
1/23/2014	PJM	Mid-Atlantic region, AP and Dominion Control Zones		BGE, Pepco			Mid-Atlantic region, AP and Dominion Control Zones	Mid-Atlantic region, AP and Dominion Control Zones	Mid-Atlantic region, AP and Dominion Control Zones	
1/24/2014	PJM	Mid-Atlantic				PJM	Mid-Atlantic region, AP and Dominion Control Zones	Mid-Atlantic region, AP and Dominion Control Zones	Mid-Atlantic region, AP and Dominion Control Zones	
1/27/2014	PJM									
1/28/2014	PJM	PJM	PJM	PJM						
1/29/2014	PJM									
1/30/2014						PJM	Mid-Atlantic and Dominion			
2/6/2014	ComEd									
2/7/2014	PJM Western Region									
2/10/2014	PJM Western Region									
2/11/2014	PJM Western Region									
2/12/2014	PJM Western Region									
2/24/2014	ComEd									
2/25/2014	ComEd									
2/26/2014	ComEd									
2/27/2014	ComEd									
2/28/2014	PJM Mid-Atlantic and Western regions									
3/4/2014	PJM	Mid-Atlantic and Dominion	PJM				PJM	PJM	PJM	
3/13/2014	PJM Western Region									

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 value of reserves is included as a penalty factor in the optimization and in the price of energy.[78] Shortage pricing is also triggered when PJM issues a voltage reduction action or a manual load dump action for a reserve zone or a reserve sub-zone. When shortage pricing is triggered, the primary reserve penalty factor and the synchronized reserve penalty factor are incorporated in the calculation of the synchronized and non-synchronized reserve market clearing prices and the locational marginal price.

In the first three months of 2014, shortage pricing was triggered on two days in January. On January 6, shortage pricing was triggered by a voltage reduction action that was issued at 1950 EPT and terminated at 2045. On January 7, shortage pricing was triggered by a shortage of primary and synchronized reserves starting in the hour beginning 0700 EPT and was in effect until 1220 during the morning peak as well as between 1755 and 1810 during the evening peak.

January 6, 2014

On January 3, PJM declared a cold weather alert for January 6 for the RTO excluding the Mid-Atlantic region and Dominion Control Zone. On January 6, PJM declared a voltage reduction warning and reduction of non-critical plant load at 1927 for the RTO. At 1933, PJM declared a maximum emergency generation action. At 1950 EPT, PJM declared a five percent voltage reduction action for the RTO that triggered shortage pricing. The event lasted for less than an hour and was cancelled at 2045.

78 See PJM OATT, 2.2 (d) General, (February 25, 2014), pp. 1815, 1819.

January 7, 2014

On January 6, at 1125, PJM issued a maximum emergency generation alert for the RTO for January 7. At 0055 on January 7, a primary reserve warning was issued for the RTO. On January 7 at 0153, PJM issued a request to purchase emergency energy for delivery between 0600 and 1100.[79] At 0251, PJM declared a voltage reduction warning and reduction of non-critical plant load for the RTO. At 0430, PJM declared a maximum emergency generation action for the RTO. Also at 0430, PJM issued emergency mandatory load management for both short lead and long lead demand resources for the RTO. Shortage pricing was triggered at 0725. It ended at 1220 when primary and synchronized reserves increased to greater than the required levels. The primary reserve warning, voltage reduction warning and the maximum emergency generation action were cancelled at 1214.

At 1330, PJM issued another request to purchase emergency energy for delivery between 1700 and 2100 EPT. At 1500, PJM declared another maximum emergency action and issued emergency mandatory load management for both short and long lead demand resources for the RTO. Shortage pricing was in effect between 1755 and 1810. The request for emergency energy purchase as well as maximum energy generation action was called off at 1816.

Analysis of emergency events in January 2014

Extreme cold weather conditions in January resulted in record PJM winter peak loads. The high demand combined with high forced outage rates, and supply interruptions for natural gas fueled generation resulted in low reserve margins and associated shortage pricing events, and high uplift payments in January.

In the period from January 6 through January 8, a polar vortex weather event caused extreme cold weather conditions in the PJM territory. On January

79 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), pp. 23-25.

3, PJM called cold weather alerts for January 6 (PJM territory except Mid-Atlantic and Dominion regions) and January 7 (for the RTO). PJM winter load reached its all time peak on January 7 for the hour ending 1900 at 140,467 MW.

FERC Waivers

On January 3, 2014, PJM submitted two requests for waivers of limits on information sharing in section 18.17.1 of the Operating Agreement (OA). The waivers would allow PJM to share market sensitive information with interstate natural gas pipelines to coordinate for ensuring reliability during the period of extreme winter weather. Section 18.17.1 of the OA prohibits PJM from disclosing to its members or third parties, confidential or market sensitive information of a member without prior authorization. The request for waiver in docket number ER14-952-000 was for a limited period in light of the extreme weather conditions forecast during the period from January 4, 2014 through January 10, 2014.[80] The request for waiver in docket number ER14-951-000 was for the period from January 11, 2014 through the end of the winter heating season.[81] On January 6, the commission issued an order granting the limited waiver and on January 17, the commission issued an order granting the longer term waiver allowing PJM to communicate and coordinate unit commitment schedules with interstate gas pipeline operators.[82,83]

On January 23, 2014, PJM submitted two additional requests for waivers, in this case of provisions in the PJM Tariff related to the $1,000/MWh cap on cost-based energy offers. In docket number ER14-1144-000, PJM requested a waiver that allows generators for which the offer cap prevented the recovery of actual marginal energy costs to be made whole effective January 24, 2014.[84] On January 24, the commission granted the waiver while directing the MMU to submit an informational filing within 30 days of the expiration of the waiver with data on the amount of MWh that cleared above the cap and the cost of such energy.[85] In docket number ER14-1145-000, PJM requested a waiver of the $1,000/MWh energy offer price cap in order to allow cost-based offers to reflect the high fuel prices for generators in the PJM territory through March 31, 2014.[86] On February 11, the commission granted the waiver lifting the cap on energy cost based offers effective through March 31.[87]

The MMU submitted a report on March 26, 2014 pursuant to the January 24 commission order.[88] The MMU reported that there were seven units belonging to three market participants that initially requested make whole payments associated with incurred costs that were not recovered as a result of the $1,000 per MWh offer cap, of which three units subsequently withdrew their requests. The total additional make whole payment requested by the participants was $583,774.38. The MMU analysis concluded that the total additional make whole payment required was $9,118.43. The primary reasons for the differences between the participants' estimates and the MMU's calculations were the ten percent adder, the actual fuel costs incurred and the actual unit heat rates.

The MMU submitted a report on April 30, 2014 pursuant to the February 11 commission order.[89] The MMU found that there were no cost-based energy offers submitted with incremental curve offer components above $1,000 per MWh. There were no LMPs above $1,000 per MWh as a direct result of the waiver granted by the commission. The total offer or operating rate at a specified output level is the sum of the total incremental costs to operate at that level as determined from the incremental curve and the no load component, divided by the output level in MWh. The $1,000 per MWh offer cap refers to the complete offer of the unit, rather than just the incremental part of the offer. An offer cap that applied solely to the incremental rate would be easy to avoid by increasing the no load rate. A generation owner may change the startup and no load components of price-based offers only semiannually on defined dates, while the startup and no load components of cost-based offers may be changed daily as costs change and the cost-based startup and no load components of price-based offers may also be changed daily as costs change.[90] The definition of the no load component of cost-based offers does

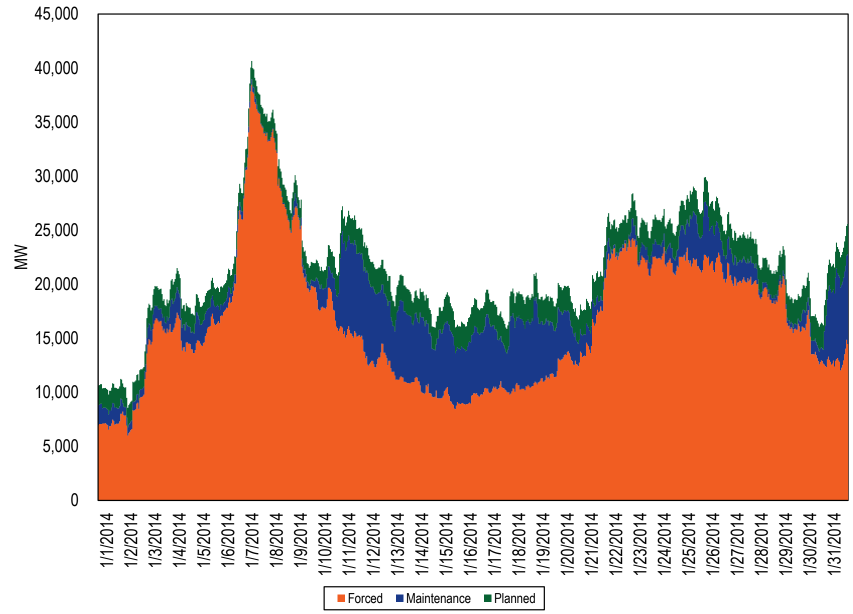
80 "Request for waiver and expedited relief of PJM Interconnection, L.L.C.," Docket No. ER14-952-000 (January 3, 2014).
81 "Request for waiver of PJM Interconnection, L.L.C.," Docket No. ER14-951-000 (January 3, 2014).
82 146 FERC ¶ 61,003 (January 6, 2014).
83 146 FERC ¶ 61,033 (January 17, 2014).
84 "Request of PJM Interconnection, L.L.C. for waiver and for commission action by January 24, 2014," Docket No. ER14-1144-000 (January 23, 2014).
85 146 FERC ¶ 61,041 (January 24, 2014).
86 "Request of PJM Interconnection, L.L.C. for waiver, request for 7-day comment period, and request for commission action by February 10, 2014," Docket No. ER14-1145-000 (January 23, 2014).
87 146 FERC ¶ 61,078 (February 11, 2014).
88 "Informational Filing re Waiver to Permit Make-Whole Payments," Docket No. ER14-1144-000 (March 26, 2014).
89 "Report on PJM Energy Market Offers, February 11 to March 31, 2014," Docket No. ER14-1145-000 (April 30, 2014).
90 See PJM Operating Agreement Schedule 1 § 1.9.7(b).

not permit the transfer of costs from the incremental curve component to the no load component. The MMU's review showed that some units' energy offers, including the no load and incremental components, did exceed $1,000 per MWh but that none of those units ran with those offers, none of these offers directly affected energy market prices and no uplift payments were made to those units. The MMU is investigating the offer behavior of several units and will take appropriate actions consistent with Attachment M of the PJM tariff.[91]

Generator outages

The maximum level of generating capacity on outage was 40,665 MW on January 7, 2014, for the hour ending 0900, of which 38,452 MW were forced outages. During the period from January 17 through January 29, 2014, the maximum MW on outage was 29,912 MW on January 26 for the hour ending 0300. While outage levels were better during the second half of January, outage levels were still well above average. Figure 3-34 shows the total MW on outage in January 2014 by the type of outage.

Figure 3-34 Generator outages in January 2014 by type of outage



91 See PJM Open Access Transmission Tariff Attachment M § IV.

Figure 3-35 shows the total MW on outage by unit fuel source.

Figure 3-35 Generator outages in January 2014 by unit fuel source

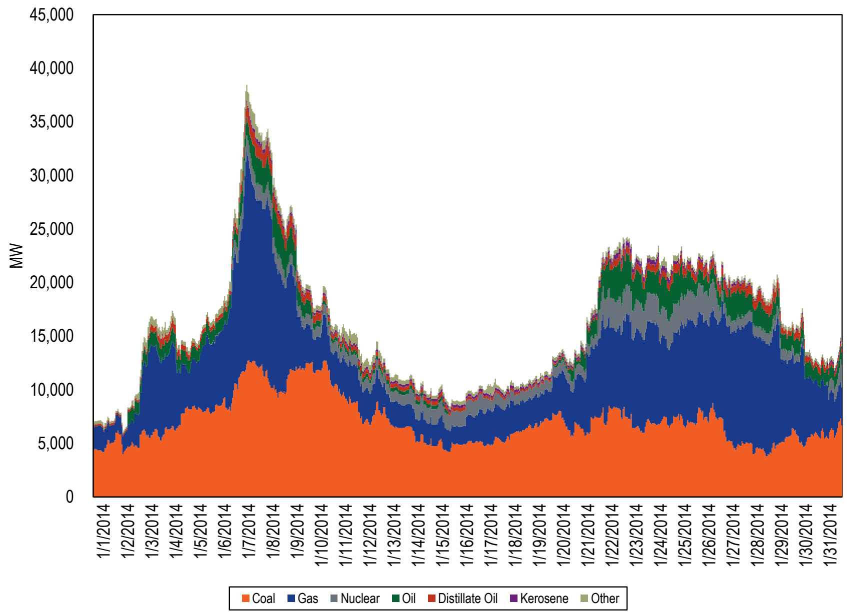
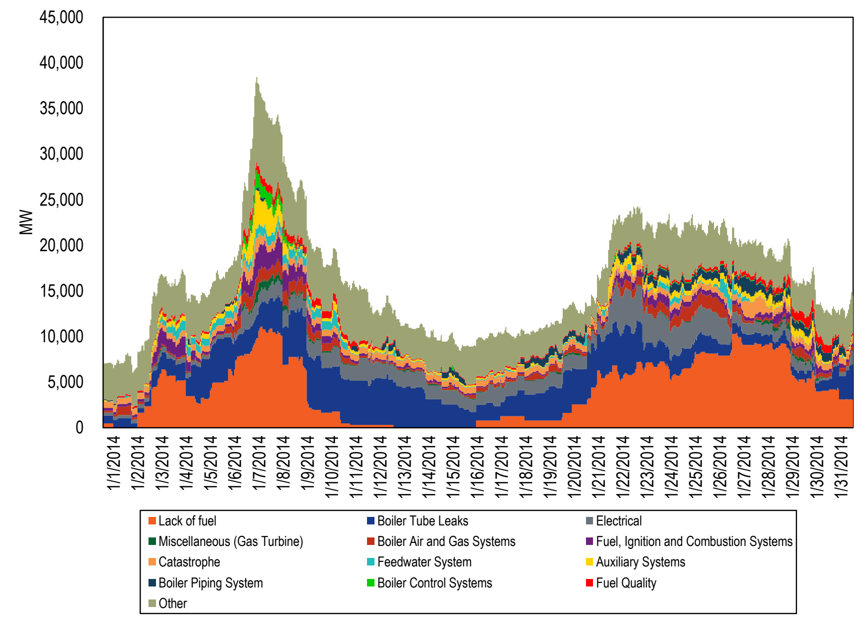


Figure 3-36 shows the forced outage MW in January by cause. Lack of fuel is the largest cause of forced outages. In addition to the lack of fuel for natural gas fired generation, some coal fired units were on forced outage because the gas required to start was not available. During the hour ending 1900 on January 7, the winter peak load hour, 10,404 MW of generation was forced out due to lack of fuel out of a total of 34,603 MW of generation on forced outage.

Figure 3-36 Forced outage MW in January 2014 by cause



Capacity market incentives

The performance incentives for capacity resources need to be substantially strengthened as the high level of outages of capacity resources during January demonstrates. One specific incentive issue stands out based on the January experience. There is a provision in the PJM tariff that allows single-fueled, natural gas fired units to exclude outages during the winter peak hour period when the outage is for lack of fuel from the calculation of the peak period Equivalent Forced Outage Rate (EFORp) which directly affects the revenue received by capacity resources.[92] As a result of this exception, a participant that produces power by procuring gas and/or a backup fuel during the winter peak period and a participant that chooses to report a lack of fuel outage and produces no energy during the winter peak period are treated as if they performed identically. If the capacity payment is not reduced when a unit is

92 PJM. OATT Attachment DD § 7.10 (e).

unavailable during the winter peak period, there is no incentive for single-fueled natural gas fired units to take all possible measures to procure gas during winter peak periods. That is the obligation of capacity resources that are paid the capacity market clearing price.

The MMU recommends that the exception to the calculation of EFORp related to the lack of gas supply during the winter for single-fuel gas fired generators be removed and that the performance incentives of capacity resources be strengthened to be consistent with the incentives that would exist in an energy only market.

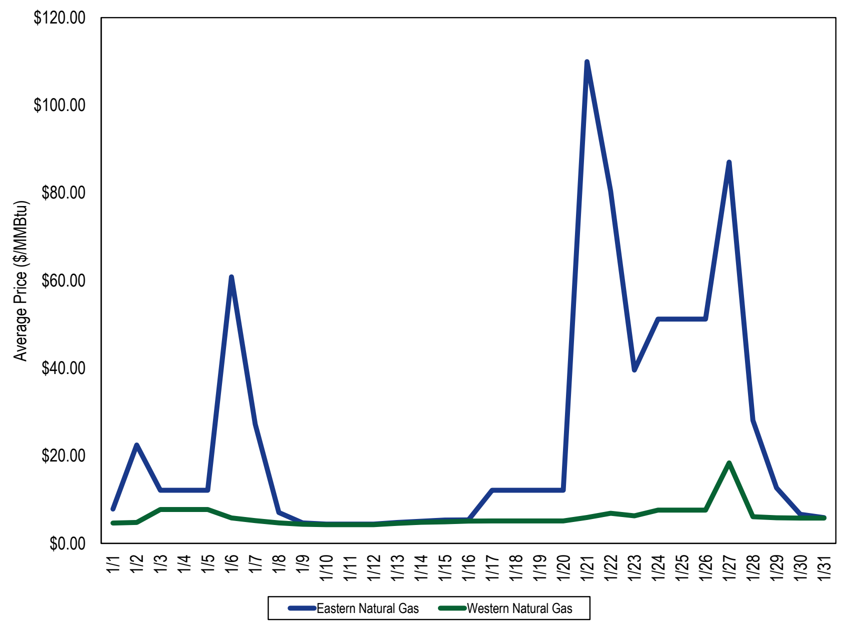
Natural gas supply and prices

As of January 1, 2014, gas fired generation was 29.2 percent (53,395.0 MW) of the total installed PJM capacity (183,095.2 MW).[93] The extreme cold weather conditions and the associated high demand for natural gas led to supply constraints on the gas transmission system which resulted in natural gas price volatility and interruptions to customers without firm transportation. Figure 3-37 shows the average daily price of delivered natural gas for eastern and western parts of PJM service territory in January.

During the first three months of 2014, a number of interstate gas pipelines that supply fuel for generators in the PJM service territory issued notices for lack of non-firm gas availability.[94] These notices include warnings of operational flow orders (OFO) and actual OFOs. OFOs restrict the provision of gas above or below the 24 hour ratable take which means that hourly nominations must be the same for each of the 24 hours in the day, with penalties for deviating from the nomination amounts. Pipelines also enforce strict balancing constraints which limit the ability of gas users to deviate from the 24 hour ratable take and which limit the ability of users to have access to unused gas. These restrictions impose risks and costs on gas fired generation.

The extreme conditions illustrate the shortcomings of a gas pipeline system that relies on individual pipelines to manage the balancing of supply and demand. Pipeline operators use restrictive and inflexible rules to manage the balance of supply and demand. The experience of pipelines and electric generators in these extreme conditions also suggests the potential benefits of creating an ISO/RTO structure to coordinate the supply of gas across pipelines and with the electric RTOs, or the inclusion of gas coordination under existing electric ISO/RTOs.

Figure 3-37 Average daily delivered price for natural gas: January 2014 ($/MMBtu)



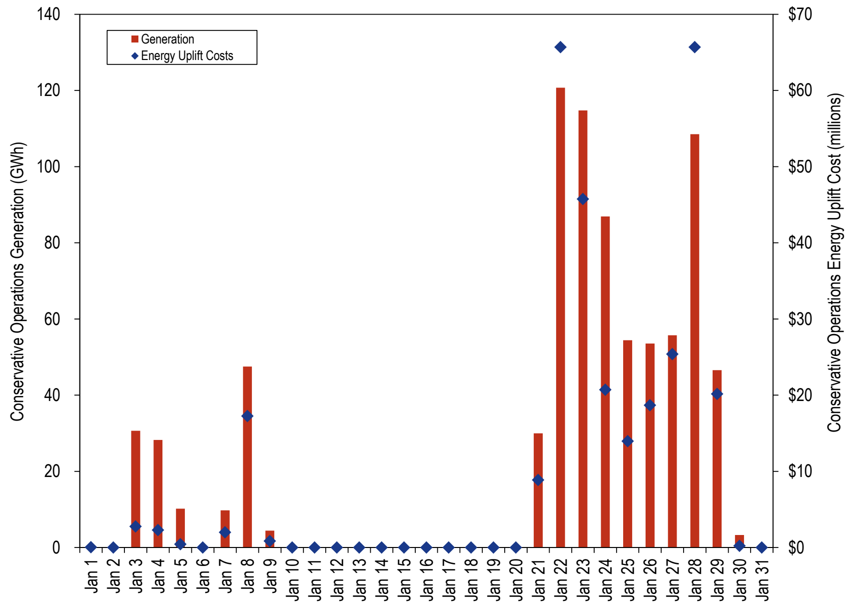
Conservative operations and energy uplift costs

Energy uplift costs due to conservative operations were a primary cause of high energy uplift costs in January. PJM invokes conservative operations when there is significant stress on the grid. Some of the actions taken by PJM during conservative operations include notifying and committing units before

93 *2014 Quarterly State of the Market Report for PJM: January through March*, Section 5: Capacity Market at Installed Capacity.
94 See PJM. *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (May 8, 2014) at 'Appendix C' for details on critical notices by natural gas pipelines serving the PJM territory.

the operating day to ensure or confirm their availability.[95] Balancing operating reserve credits paid to units committed before the operating day for reliability purposes in January were $310.6 million or 51.8 percent of all energy uplift costs in the month. Figure 3-38 shows the generation in GWh committed for conservative operations before the operating day and the balancing operating reserve credits paid to those units. PJM's commitment of units for conservative operations means that PJM committed the units based on concern about meeting load during peak hours, providing additional reserves as a buffer against a disturbance in the system and reducing operational uncertainty in general. Energy uplift credits increased when units were kept online even when noneconomic as a result of uncertainty about the ability to restart, and uncertainties about the ability to procure natural gas.

Figure 3-38 Conservative operations generation and energy uplift costs: January 2014



95 See PJM "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), pp. 40-41 for further details on the triggers and actions of conservative operations.

Demand response

PJM requested voluntary response from emergency demand resources (DR) on six days, eight total events, in the first three months of 2014 in all or parts of the service territory. Table 3-77 shows the date and the areas for which demand resources were requested. PJM requested both long lead and short lead DR for all of the eight events. Emergency demand resources have only a limited requirement to respond to PJM calls, including only peak hours during summer months. As a result, unlike other capacity resources, demand response was not available in January. Any response to PJM's declaration of emergency load management events was voluntary and performance or lack of performance during these events is not accounted for compliance.[96] Some demand resources did respond to PJM's requests. Demand resources were determined to be marginal and set LMP at $1,800 per MWh or more in some intervals.

Day-ahead and real-time LMP

Prices in January fluctuated during the cold weather events in January. (Figure 3-39) Real-time prices were higher than day-ahead prices during January 7 and 8. Day-ahead prices were higher than real-time prices at times in the later part of January. (Figure 3-40) The relationship between day-ahead and real-time prices is a complex function of PJM actions, market supply and demand conditions, participant behavior and participant expectations.

96 See *2014 Quarterly State of the Market Report for PJM: January through March*, Section 6: Demand Response at 'Emergency Event Reported Compliance' for performance statistics during these events.

Figure 3-39 PJM real-time and day-ahead hourly LMP: January 2014

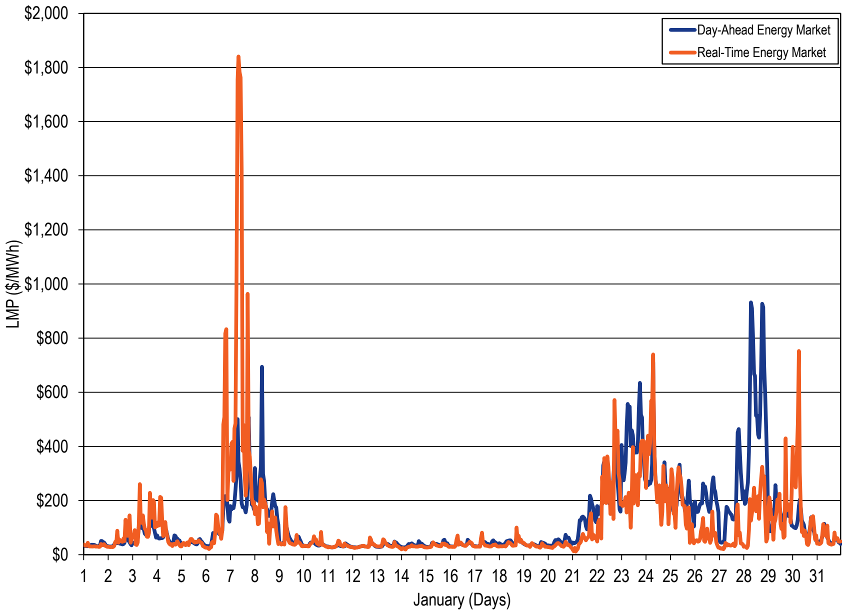
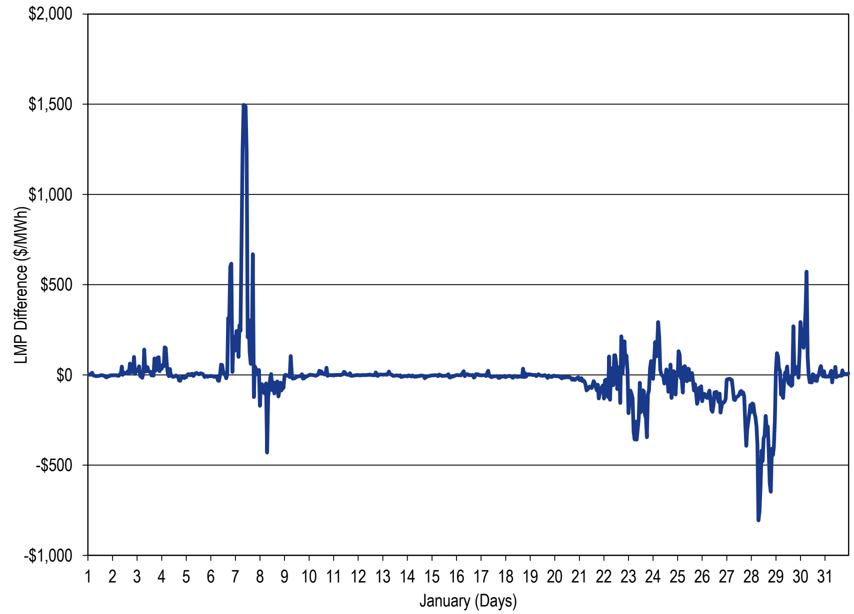


Figure 3-40 Real-time hourly LMP minus day-ahead hourly LMP: January 2014



The real-time average hourly LMP on January 7 for HE 0900 was $1,840.54, greater than the highest possible offer price of $1,800 per MWh. The LMP is the marginal price of energy at a bus. The system marginal price (SMP) component of LMP at a bus is the system price at a distributed load-weighted reference bus. SMP is the incremental cost of energy, ignoring losses and congestion. The SMP is the same throughout the system, while the congestion and loss components of LMP will either be positive or negative in a specific area.[97] The SMP cannot exceed the incremental cost of energy from the most expensive resource on the system.

Following the implementation of shortage pricing, generator offers remained capped at $1,000 per MWh but demand response offers were capped at $1,800 for the period between June 1, 2013, and May 31, 2014. The $1,800 is equal

97 For more discussion of the components of price see the *2013 State of the Market Report for PJM, Volume II*, Section 11, "Congestion and Marginal Losses."

to the generator offer cap plus the sum of the applicable penalty factors ($800 per MWh) for synchronized reserves and non-synchronized primary reserves. This means that the highest possible SMP is $1,800 in the period between June 1, 2013, and May 31, 2014 unless there are emergency purchases on the margins with higher prices. SMP did exceed $1,800 per MWh in some intervals in which there were no emergency purchases. This suggests that the prices in excess of $1,800 per MWh on January 7, 2014, were a result of the way in which PJM modeled zonal (not nodal) demand response as a marginal resource.

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 limits on its availability as a result of environmental limitations, short term fuel limitations, or emergency conditions at the unit, or if the additional capacity is obtained by operating the unit past its normal limits.[98,99] 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. If units are not designated maximum emergency and they do not respond to PJM dispatch requests, they are considered to be on a forced outage.

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 is expected to experience possible resource adequacy issues as a result of forecast temperatures below ten degrees Fahrenheit.[100] 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.[101] 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.[102] 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 because it does not require the declaration of an outage which can reduce the level of capacity offered in the capacity market. 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.[103]

Participant behavior during cold weather days in January

The high-demand days in January resulted in higher fuel costs and therefore in higher offer prices for gas fired units. That is expected behavior in a competitive market. However, some coal units also increased their offer prices significantly, including offers at $1,000 per MWh, in anticipation that their generation would be committed regardless of their offer price. Given that coal costs did not increase, this behavior is consistent with economic withholding.

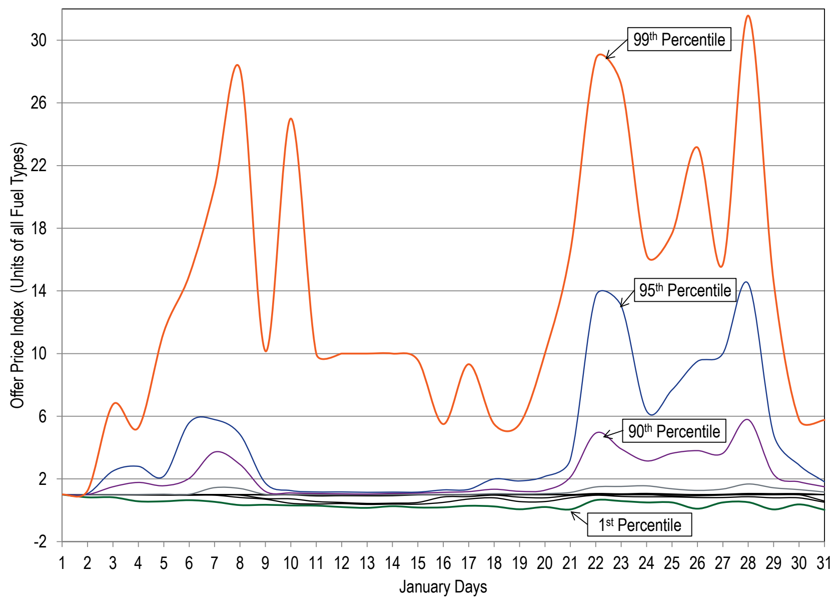
Figure 3-41 shows the distribution of change in cleared offer prices at generating units' economic minimum output level in the month of January. The offer price index is the ratio of a unit's offer at its economic minimum on

98 See PJM OATT, 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.
99 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), p. 74.
100 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), p. 41.
101 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), p. 86.
102 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), pp 73-74.
103 See PJM OATT, 6A.1.3 Maximum Emergency, (February 25, 2014) p. 1740, 1796.

the specified day to its offer at its economic minimum on January 1, 2014.[104] For example, if a unit offered its economic minimum output at $50 per MWh on January 1, and offered its economic minimum output at $100 per MWh on January 7, the unit's offer price index for January 7 is calculated as 2.0.

Figure 3-41 shows that a substantial number of committed units increased their offers, particularly for the forecasted cold days in January. On January 8, among committed units, ten percent of units increased their offers to 3.0 times the offer level on January 1, five percent of units increased their offers to 4.8 times the level offered on January 1, and one percent of units increased their offers to 28.0 times the offer level on January 1.

Figure 3-41 Distributions of Offer Prices, All Units: January 2014



104 In instances where a unit did not offer its generation on January 1, 2014, the earliest day on which the unit submitted its offer is chosen as the reference day. For units that did not submit price based offers, cost based offers were used.

Most of the increased offer prices were from generators using natural gas facing very high fuel prices. Figure 3-42 shows the behavior of gas fired units in January. For example, on January 22, among committed natural gas units, 10 percent increased their offers to 13 times the offer level on January 1, five percent increased their offers to 19 times the offer level on January 1, and one percent increased their offers to 28.0 times the offer level on January 1.

Figure 3-42 Distributions of Offer Prices, Gas Units: January 2014

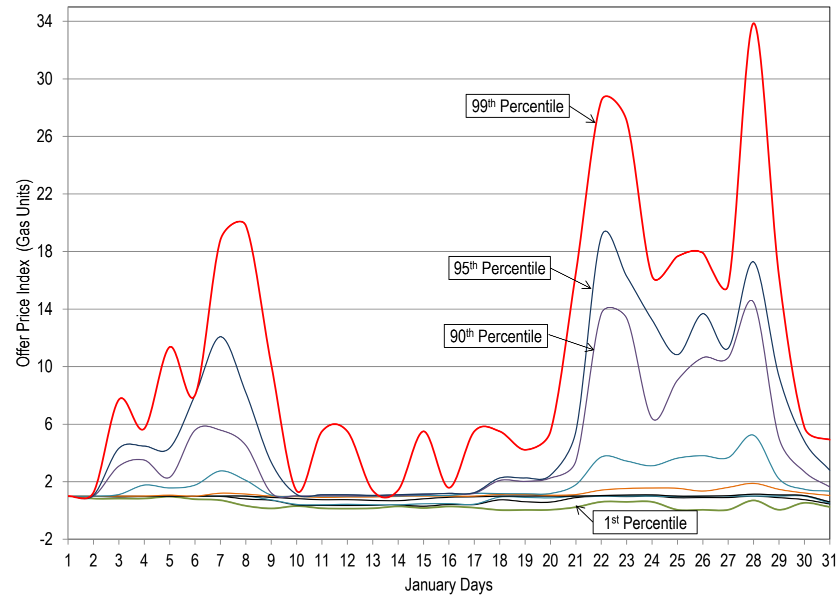
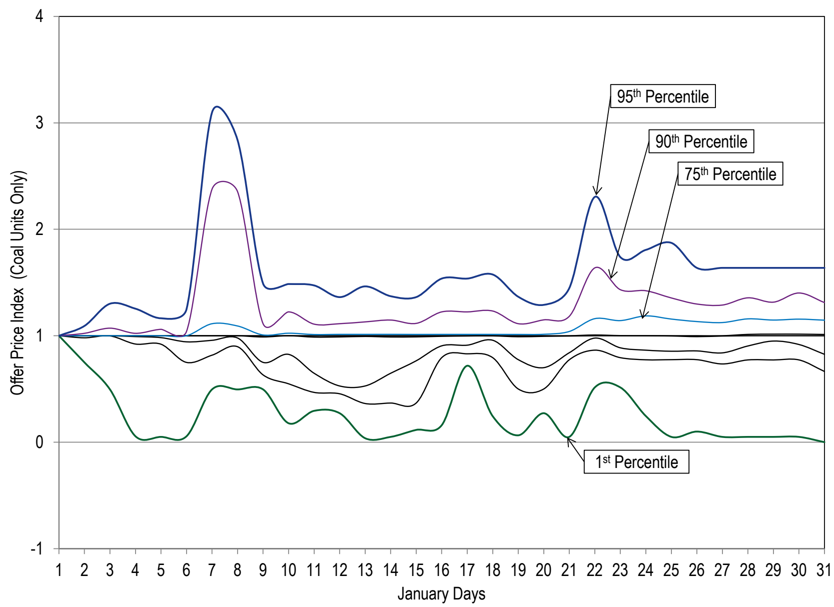


Figure 3-43 shows that a substantial number of coal units also increased their offers for the forecasted cold days in January, although fuel costs do not explain these increase. For example, on January 8, among committed coal units, 10 percent increased their offers to 2.3 times the offer level on January 1 and five percent increased their offers to 3.0 times the offer level on January 1.

Figure 3-43 Distributions of Offer Prices, Coal Units: January 2014



Real-time markup on high demand days in January

Markup is calculated as the difference between the price-based offer and the cost-based offer of the marginal unit at its dispatched MW output. The MMU calculates the impact on system prices of marginal unit markup. The calculation shows the markup component of LMP based on the mark up of each actual marginal unit on the system.[105] Figure 3-44 shows the hourly markup component of PJM LMP for January. The markup component of real-time LMP was high on high-demand days in January 2014. For comparison, negative \$3.12 per MWh or negative 8.3 percent of the PJM real-time load-weighted average LMP was attributable to markup in January 2013, whereas \$6.51 per MWh or 5.1 percent of the PJM real-time load-weighted average LMP was attributable to markup in January 2014. This outcome is consistent with the hypothesis that some coal unit owners engaged in economic withholding by increasing markups in anticipation of high demand days on which they were likely to be dispatched.

105 See the *2013 State of the Market Report for PJM, Volume II and Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors." for more information.

Figure 3-44 Hourly Markup Component of PJM's system-wide real-time LMP: January 2014

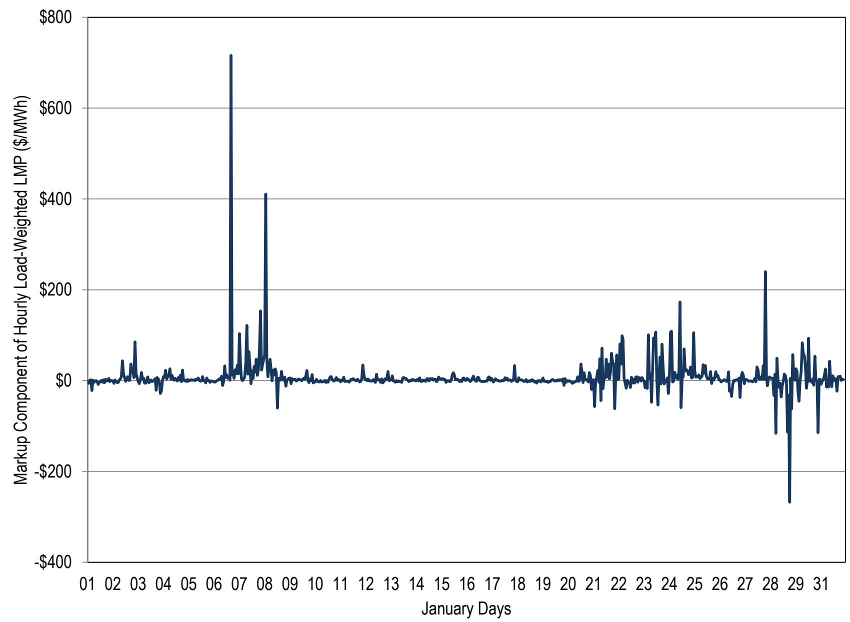


Figure 3-45 shows the markup component of PJM average daily real-time load-weighted LMP by fuel type. On many of the high demand days, coal units accounted for a substantial proportion of the markup component of PJM LMP. For example, on January 8, markup resulted in a \$46 per MWh addition or 32 percent of the day's load-weighted LMP, of which coal units' markup accounted for \$31 per MWh or 21.8 percent of the day's load-weighted LMP.

Figure 3-45 Daily Markup Contribution to the Real-time Load-weighted LMP by Fuel Type: January 2014

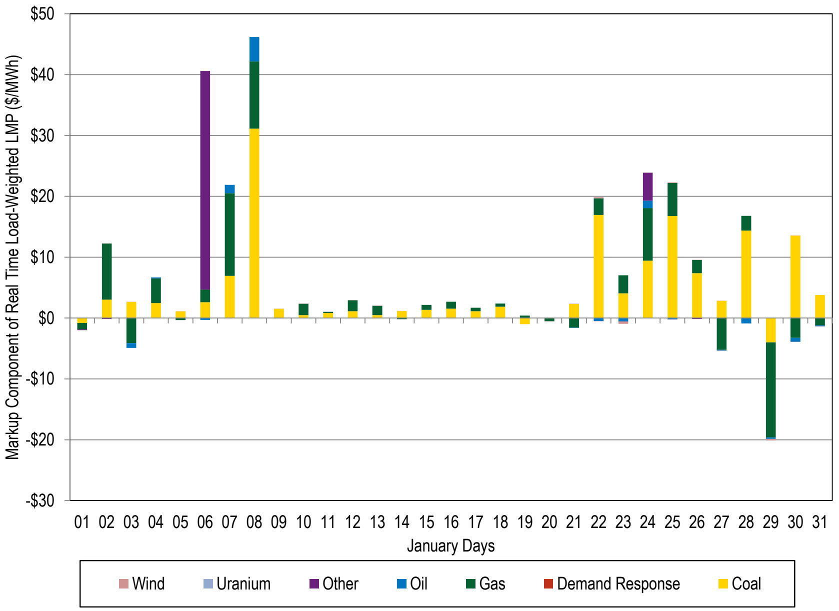
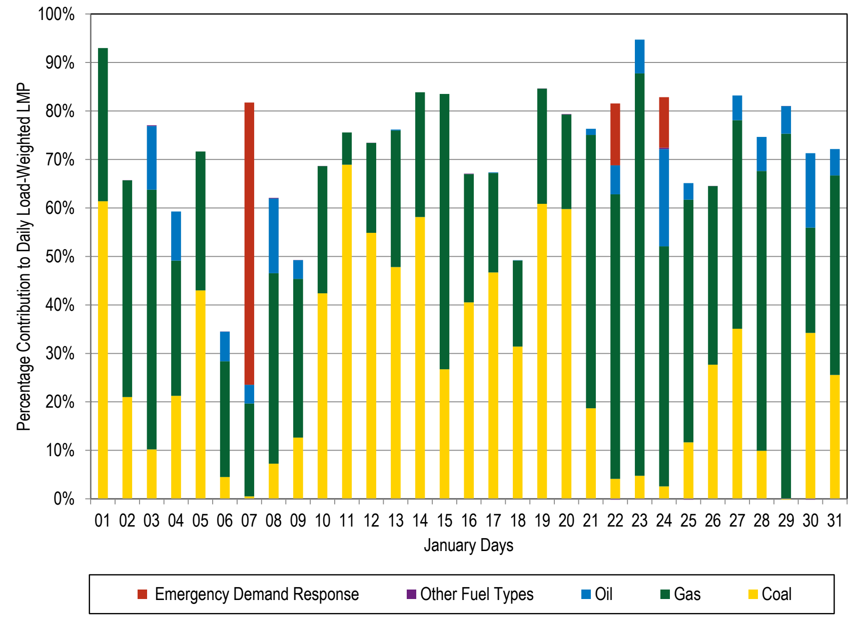


Figure 3-46 Percentage Contribution of Fuel Cost to Daily Load-weighted Real Time LMP: January 2014



Marginal fuel

Figure 3-46 shows percentage contribution of a fuel cost and emergency demand response to the daily load-weighted LMP. On high-demand days in January, natural gas units contributed a larger share relative to the coal units to the PJM system-wide load weighted LMP. Even though natural gas units had a higher contribution to the load-weighted LMP than that of coal units, their markup contribution was not similarly higher than that of coal units during those high-demand days. The expensive offers from natural gas units were primarily due to high fuel costs faced by those units in contrast to coal units, who did not face the same level of fuel-price volatility as natural gas units in January.

Interchange transactions

On January 7, 2014, at 0630, as part of the PJM/VACAR reserve sharing agreement, Progress Energy Carolinas (PEC) requested 200 MW of shared reserves from PJM on behalf of South Carolina Energy and Gas (SCE&G) due to the loss of a 600 MW unit. PJM activated the shared reserves. At 0715, PJM informed PEC that they would need to recall the shared reserves, and at 0730, the shared reserve event ended. SCE&G shed 100 MW of load to maintain generation/load balance. At approximately 0815, PEC again requested 200 MW of shared reserves from PJM on behalf of SCE&G. As a result of the loss of generation and a spinning event, PJM was only able to provide the 200 MW of reserve sharing for 10 minutes, and recalled the 200 MW at 0825. At approximately 0830, SCE&G shed an additional 200 MW of load. At 0845, PJM provided 200 MW of shared reserves for SCE&G and an additional 200

MW for PEC. The 200 MW reserves provided to PEC ended at 1030 and the 200 MW of reserves provided for SCE&G ended at 2130.

On January 7, 2014, PJM issued a request for emergency energy bids on two separate occasions. The first request was for the period between 0600 and 1100 hours and the second request was for the period between 1700 and 2100 hours. The emergency bids PJM accepted had prices between $800 and $3,200 per MWh, and minimum durations between 1 and 8 hours. PJM purchased emergency power in hours ending 0700 through 1100 and again in hours ending 1300 through 2300. The emergency power purchase volumes ranged from 150 MWh in hour ending 1200 to the maximum of 1,474 MWh in hour ending 1700.

On January 7, 2014, while PJM was a net importer of energy in all hours, PJM continued to export energy on both non-firm and firm transmission during the periods of emergency procedures on January 7. Some export transactions were from PJM capacity resources and some export transactions were from units that were not PJM capacity resources. Energy exports from PJM capacity resources are recallable under emergency conditions and energy from units that are not capacity resources are not recallable by PJM. The largest volume of export transactions occurred in hour ending 1000, 5,554 MW, of which 3,816 MW were from PJM capacity resources.

The MMU recommends that PJM create and implement clear, explicit and detailed rules that define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. The MMU recommends that PJM create and implement clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources.