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 nine 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 nine 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 nine months of 2014 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1154 with a minimum of 930 and a maximum of 1468 in the first nine 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 periods of high demand 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.

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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 4,934 MW, or 2.8 percent, from 175,960 MW in the first nine months of 2013 to 171,026 MW in the first nine months of 2014.[4] In the first nine months of 2014, 2,515 MW of new capacity were added to PJM. This new generation was more than offset by the deactivation of 12 units (1,526 MW) since January 1, 2014.

  PJM average real-time generation in the first nine months of 2014 increased by 2.2 percent from the first nine months of 2013, from 90,432 MW to 92,449 MW. The PJM average real-time generation in the first nine months of 2014 would have increased by 1.4 percent from the first nine months of 2013, from 90,432 MW to 91,701 MW, if the EKPC Transmission Zone had not been included.[5]

  PJM average day-ahead supply in the first nine months of 2014, including INCs and up-to congestion transactions, increased by 8.5 percent from the first nine months of 2013, from 148,489 MW to 161,137 MW. The PJM average day-ahead supply, including INCs and up-to congestion transactions, would have increased by 7.8 percent from the first nine months of 2013, from 148,489 MW to 160,078 MW, if the EKPC Transmission Zone had not been included. The day-ahead supply growth was 286.4 percent higher than the real-time generation growth as a result of the continued growth, until September 8, 2014, 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 nine months of 2014, coal units provided 44.4 percent, nuclear units 33.7 percent and gas units 17.1 percent of total generation. Compared to the first nine months of 2013, generation from coal units increased 2.3 percent, generation from gas units increased 6.0 percent and generation from nuclear units remained the same.

- **Marginal Resources.** In the PJM Real-Time Energy Market, during the first nine months of 2014, coal units were 49.8 percent of marginal resources and natural gas units were 42.4 percent of marginal resources. In the first nine months of 2013, coal units were 57.6 percent and natural gas units were 34.1 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market, during the first nine months of 2014, up-to congestion transactions were 93.6 percent of marginal resources, INCs were 1.6 percent of marginal resources, DECs were 2.2 percent of marginal resources, and generation resources were 2.5 percent of marginal resources in the first nine months of 2014.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM system peak load during the first nine months of 2014 was 141,673 MW in the HE 1700 on June 17, 2014, which was 15,835 MW, or 10.1 percent, lower than the PJM peak load for the first nine months of 2013, which was 157,508 MW in the HE 1700 on July 18, 2013.

3 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.
4 Calculated values shown in Section 3, "Energy Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.
5 The EKPC Zone was integrated on June 1, 2013.

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PJM average real-time load in the first nine months of 2014 increased by 1.6 percent from the first nine months of 2013, from 89,123 MW to 90,567 MW. The PJM average real-time load in the first nine months of 2014 would have increased by 0.7 percent from the first nine months of 2013, from 89,123 MW to 89,707 MW, if the EKPC Transmission Zone had not been included.

PJM average day-ahead demand in the first nine months of 2014, including DECs and up-to congestion transactions, increased by 7.9 percent from the first nine months of 2013, from 145,139 MW to 156,542 MW. The PJM average day-ahead demand, including DECs and up-to congestion transactions, would have increased by 7.1 percent from the first nine months of 2013, from 145,139 MW to 155,420 MW, if the EKPC Transmission Zone had not been included. The day-ahead demand growth was 393.8 percent higher than the real-time load growth as a result of the continued growth, until September 8, 2014, 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 nine months of 2014, 10.2 percent of real-time load was supplied by bilateral contracts, 27.4 percent by spot market purchases and 62.5 percent by self-supply. Compared with 2013, reliance on bilateral contracts decreased 0.4 percentage points, reliance on spot market purchases increased by 2.4 percentage points and reliance on self-supply decreased by 1.9 percentage points.
- **Supply and Demand: Scarcity.** In the first nine 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 remained at 0.2 percent in the first nine months of 2013 and 2014. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.4 percent in the first nine months of 2013 to 0.5 percent in the first nine months of 2014.

  In the first nine months of 2014, 13 control zones experienced congestion resulting from one or more constraints binding for 75 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 nine months of 2013 to 0.3 percent in the first nine months of 2014. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 2.5 percent in the first nine months of 2013 to 0.3 percent in the first nine 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 nine months of 2014, 73.9 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 nine months of 2014, 9.0 percent of units had average dollar markups greater than or equal to $150. Only 4.5 percent of units had average dollar markups

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greater than or equal to $150 in the first nine months of 2013. Markups increased during the high demand days in January.

In the PJM Day-Ahead Energy Market in the first nine months of 2014, 94.8 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.02. Nonetheless, some marginal units do have substantial markups.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 104 units eligible for FMU or AU status in at least one month during the first nine months of 2014, 46 units (44.2 percent) were FMUs or AUs for all nine months, and 16 units (15.4 percent) qualified in only one month.
- **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. While up-to congestion transactions (UTC) continued to displace increment offers and decrement bids, there was a sharp decrease in UTCs in September as a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[6]
- **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 nine months of 2014, 55.9 percent were offered as available for economic dispatch, 22.8 percent were offered as self scheduled, and 21.3 percent were offered as self scheduled and dispatchable.

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 nine months of 2014 were between $800 and $900 for 4 hours, between $900 and $1,000 for one hour, greater than $1,000 for six hours, and greater than $1,800 for one hour.

  PJM Real-Time Energy Market prices increased in the first nine months of 2014 compared to the first nine months of 2013. The load-weighted average LMP was 47.4 percent higher in the first nine months of 2014 than in the first nine months of 2013, $58.60 per MWh versus $39.75 per MWh.

  PJM Day-Ahead Energy Market prices increased in the first nine months of 2014 compared to the first nine months of 2013. The load-weighted average LMP was 49.6 percent higher in the first nine months of 2014 than in the first nine months of 2013, $59.09 per MWh versus $39.49 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 nine months of 2014, 29.8 percent of the load-weighted LMP was the result of coal costs, 36.9 percent was the result of gas costs and 0.65 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market, for the first nine months of 2014, 23.3 percent of the load-weighted LMP was the result of the cost of gas, 18.5 percent was the result of the cost of coal, 13.6 percent was the result

6 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

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."

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of the cost of up-to congestion transactions and 15.8 percent was the result of the cost of DEC.

- **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 for the first nine months of 2014, the adjusted markup component of LMP was positive, $3.65 per MWh or 6.2 percent of the PJM real-time, load-weighted average LMP. The real-time load-weighted average LMP for the month of March had the highest markup component, $12.33 per MWh using adjusted cost offers, or 16.25 percent of the real-time load-weighted average LMP in March, a substantial increase over 2013. For the first nine months of 2013, the adjusted markup was $0.85 per MWh or 2.1 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 nine months of 2014, the adjusted markup component of LMP resulting from generation resources was -$0.93 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 -$0.20 per MWh in the first nine months of 2013 and -$1.04 per MWh in the first nine 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 nine 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 has recommended 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. (Priority: Medium. First reported 2012.)

  The MMU and PJM proposed, and on October 31, 2014, the Commission approved, a compromise that maintained the ability of certain generating units to qualify for FMU adders but limiting FMU adders to units with net revenues less than unit going forward costs or ACR.[8]

  The MMU considers this recommendation accepted and will review the results of the Commission order on FMU status for at least 12 months prior to considering any additional recommendation related to FMUs.

8 149 FERC ¶ 61,091 (2014).

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- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules. (Priority: Low. First reported Q2, 2014.)
- 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] (Priority: Medium. First reported 2012.)
- The MMU recommends that PJM not use the ATSI closed loop interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product. (Priority: Medium. First reported 2013.)
- 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. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 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. (Priority: Low. First reported 2013.)
- 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. (Priority: Low. First reported 2013.)
- 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] (Priority: Low. First reported 2013.)
- 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. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013.)
- 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. (Priority: Low. First reported Q1, 2014.)
- 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. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. (Priority: Medium. First reported Q1, 2014.)

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first nine months of 2014, including aggregate supply and demand, concentration ratios, three pivotal supplier test

9 PJM OATT, 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.
10 The general definition of a hub can be found in "Manual 35: Definitions and Acronyms," Revision 23 (April 11, 2014).
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.

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results, offer capping, participation in demand response programs, loads and prices.

Average real-time offered generation decreased by 4,934 MW in the first nine months of 2014 compared to the first nine months of 2013, while peak load decreased by 15,835 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 nine 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. 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

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

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 nine months of 2014.

Market Structure

Market Concentration

Analyses of supply curve segments of the PJM Energy Market for the first nine 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 nine 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]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during the first nine months of 2014 was moderately concentrated (Table 3-2).

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).

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

	Hourly Market HHI (Jan - Sep, 2013)	Hourly Market HHI (Jan - Sep, 2014)
Average	1180	1154
Minimum	871	930
Maximum	1610	1468
Highest market share (One hour)	31%	29%
Average of the highest hourly market share	22%	21%
# Hours	6,551	6,551
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

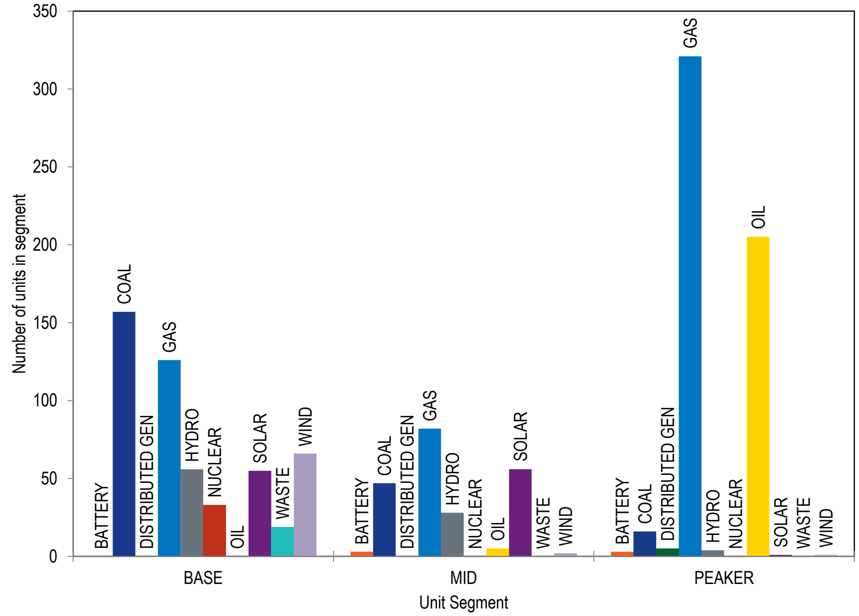
Table 3-3 includes HHI values by supply curve segment, including base, intermediate and peaking plants for the first nine months of 2013 and 2014.

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

	Jan - Sep, 2013			Jan - Sep, 2014		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	901	1095	1484	1038	1181	1484
Intermediate	835	2266	8429	771	1914	6533
Peak	694	6329	10000	702	5940	10000

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

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



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

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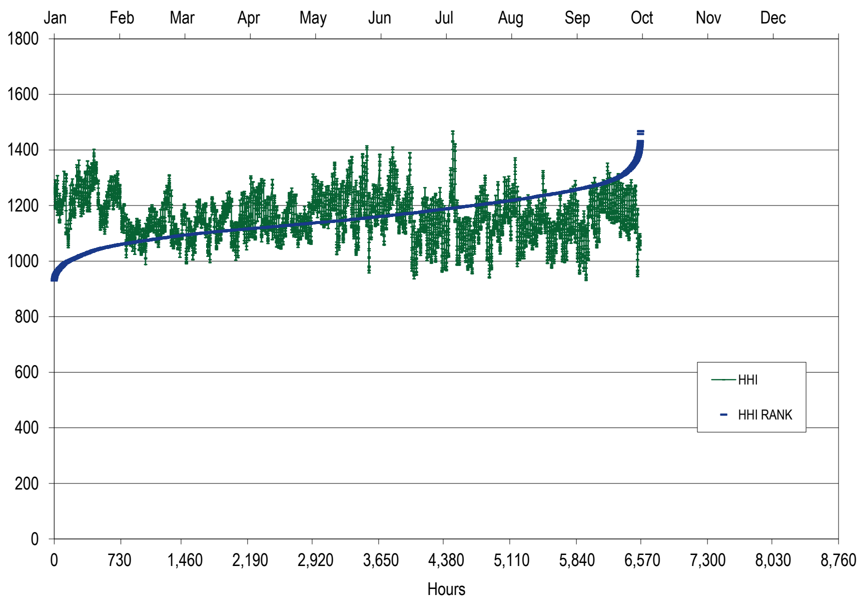
Figure 3-2 presents the hourly HHI values in chronological order and an HHI duration curve for the first nine months of 2014.

Figure 3-2 PJM hourly Energy Market HHI: January through September, 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 nine 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 nine months of 2014, the offers of one company contributed 17.1. percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 53.8 percent of the real-time, load-weighted, average PJM system LMP. During the first nine months of 2013, the offers of one company contributed 21.7 percent of the real time, load-weighted PJM system LMP and offers of the top four companies contributed 60.3 percent of the real-time, load-weighted, average PJM system LMP.

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

Table 3-4 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): January through September 2013 and 2014

2013 (Jan-Sep)		2014 (Jan-Sep)	
Company	Percent of Price	Company	Percent of Price
1	21.7%	1	17.7%
2	21.4%	2	16.1%
3	10.3%	3	12.2%
4	7.0%	4	7.7%
5	5.1%	5	6.2%
6	4.7%	6	5.5%
7	3.7%	7	5.3%
8	3.5%	8	3.7%
9	3.2%	9	3.4%
Other (58 companies)	19.5%	Other (60 companies)	22.1%

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 (20.6 percent), in the first nine months of 2013 also had the largest impact (13.8 percent) in the first nine months of 2014.

Table 3-5 Marginal resource contribution to PJM day-ahead, load-weighted LMP (By parent company): January through September 2013 and 2014

2013 (Jan - Sep)		2014 (Jan - Sep)	
Company	Percent of Price	Company	Percent of Price
1	20.6%	1	13.8%
2	10.4%	2	8.1%
3	8.4%	3	6.5%
4	7.9%	4	6.1%
5	7.4%	5	5.3%
6	4.9%	6	3.6%
7	4.0%	7	3.5%
8	3.4%	8	2.8%
9	3.1%	9	2.7%
Other (139 companies)	29.9%	Other (143 companies)	47.6%

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

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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 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 nine months of 2014, coal units were 49.77 percent and natural gas units were 42.40 percent of marginal resources. In the first nine months of 2013, coal units were 57.56 percent and natural gas units were 34.13 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.[18] In the first nine months of 2014, 75.24 percent of the wind marginal units had negative offer prices, 22.84 percent had zero offer prices and 1.74 percent had positive offer prices.

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

Type/Fuel	2013 (Jan-Sep)	2014 (Jan-Sep)
Coal	57.56%	49.77%
Gas	34.13%	42.40%
Wind	4.75%	3.86%
Oil	3.22%	3.46%
Other	0.21%	0.35%
Uranium	0.02%	0.06%
Emergency DR	0.03%	0.05%
Municipal Waste	0.08%	0.04%

Table 3-7 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first nine months of 2014, up-to congestion transactions were 93.57 percent of the total marginal resources. Up-to congestion transactions were 96.11 percent of the total marginal resources in the first nine months of 2013.[19]

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

Type/Fuel	2013 (Jan - Sep)	2014 (Jan - Sep)
Up-to Congestion Transaction	96.11%	93.57%
DEC	1.24%	2.19%
INC	1.01%	1.59%
Coal	0.97%	1.43%
Gas	0.44%	0.95%
Wind	0.16%	0.12%
Dispatchable Transaction	0.06%	0.08%
Price Sensitive Demand	0.01%	0.01%
Municipal Waste	0.00%	0.00%
Oil	0.00%	0.02%
Import	0.00%	0.03%
Other	0.00%	0.02%
Total	100.00%	100.00%

18 For the generation units that are capable of using multiple fuel types, PJM does not require the participants to disclose the fuel type associated with their offer schedule. For these units, the cleared offer schedules on a given day were compared to the cost associated with each fuel to determine the fuel type most likely to have been the basis for the cleared schedule.

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

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Figure 3-3 shows, for the day-ahead market between January 1 and September 30 of 2014, the daily proportion of marginal resources that were up-to congestion transaction and/or generation units. The percentage of marginal up-to congestion transactions decreased significantly beginning on September 8, 2014, as a result of the FERC's UTC uplift refund notice which became effective on September 8, 2014.[20] The percentage of marginal up-to congestion transaction decreased and that of generation units increased. Figure 3-4 shows the percentage of marginal up-to congestion transaction and marginal generation units from August 18, 2014 through September 30, 2014. The percentage of marginal up-to congestion transaction decreased and that of generation units, INCs and DECs increased.

Figure 3-3 Day-ahead marginal up-to congestion transaction and generation units: January through September 2014

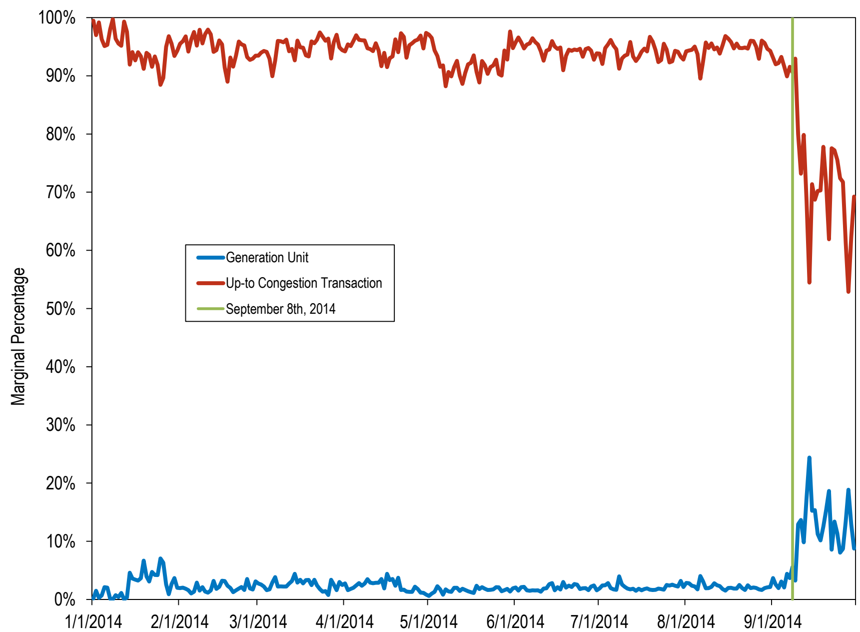
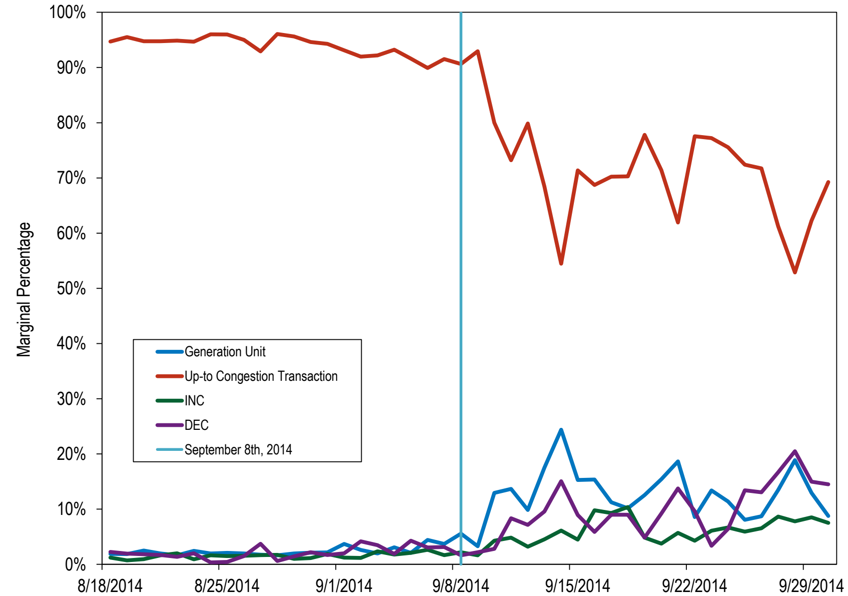


Figure 3-4 Day-ahead marginal up-to congestion transaction and generation units: August 18, 2014, through September 30, 2014



Supply

Supply includes physical generation and imports and virtual transactions.

Figure 3-5 shows the average PJM aggregate real-time generation supply curves, peak load and average load for the first nine months of 2013 and the first nine months of 2014. Total average PJM aggregate real-time generation supply decreased by 4,934 MW, or 2.8 percent, in the first nine months of 2014 from a maximum of 175,960 MW to 171,026 MW.

20 See 18 CFR § 385.213 (2014).

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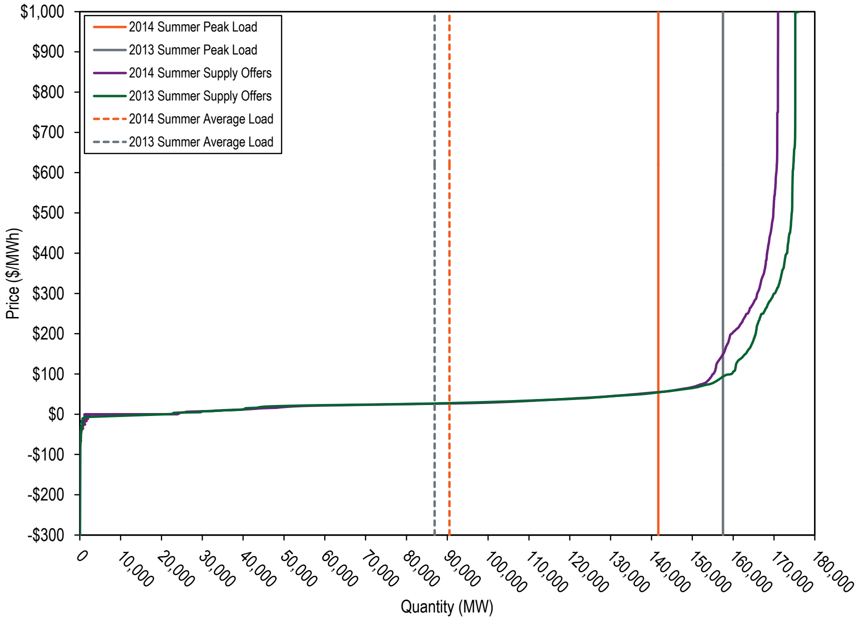
Figure 3-5 Average PJM aggregate real-time generation supply curves: January through September of 2013 and 2014



Energy Production by Fuel Source

Compared to the first nine months of 2013, generation from coal units increased 2.3 percent and generation from natural gas units increased 5.9 percent (Table 3-8).[21] Natural gas prices increased and coal prices remained relatively constant in the first nine months of 2014. Natural gas prices in the third quarter of 2014 were lower than the third quarter of 2013.

Table 3-8 PJM generation (By fuel source (GWh)): January through September of 2013 and 2014[22]

	2013 (Jan-Sep)		2014 (Jan-Sep)		Change in
	GWh	Percent	GWh	Percent	Output
Coal	267,112.3	44.5%	273,126.4	44.4%	2.3%
Standard Coal	259,835.6	43.2%	265,236.6	43.1%	2.0%
Waste Coal	7,276.7	1.2%	7,889.8	1.3%	0.2%
Nuclear	207,254.4	34.5%	207,170.7	33.7%	(0.0%)
Gas	99,264.9	16.5%	105,197.1	17.1%	6.0%
Natural Gas	97,550.2	16.2%	103,274.6	16.8%	5.9%
Landfill Gas	1,713.1	0.3%	1,786.6	0.3%	4.3%
Biomass Gas	1.7	0.0%	136.0	0.0%	8,000.1%
Hydroelectric	11,144.7	1.9%	11,601.1	1.9%	4.1%
Pumped Storage	5,277.1	0.9%	5,742.0	0.9%	8.8%
Run of River	5,867.6	1.0%	5,859.0	1.0%	(0.1%)
Wind	10,379.3	1.7%	10,723.0	1.7%	3.3%
Waste	3,719.2	0.6%	3,895.9	0.6%	4.8%
Solid Waste	3,111.9	0.5%	3,191.3	0.5%	2.6%
Miscellaneous	607.2	0.1%	704.6	0.1%	16.0%
Oil	1,620.5	0.3%	2,812.9	0.5%	73.6%
Heavy Oil	1,440.3	0.2%	2,351.0	0.4%	63.2%
Light Oil	152.4	0.0%	390.2	0.1%	156.1%
Diesel	14.1	0.0%	51.4	0.0%	264.4%
Kerosene	13.6	0.0%	20.2	0.0%	49.0%
Jet Oil	0.1	0.0%	0.1	0.0%	(56.0%)
Solar	288.4	0.0%	330.6	0.1%	14.6%
Battery	0.4	0.0%	5.8	0.0%	1,250.0%
Total	600,784.1	100.0%	614,863.3	100.0%	2.3%

21 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.

22 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.

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Table 3-9 Monthly PJM generation (By fuel source (GWh)): January through September of 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Coal	37,833.4	34,845.0	34,350.8	25,940.4	24,165.0	29,969.9	31,489.1	29,277.6	25,255.1	273,126.4
Standard Coal	36,809.3	33,985.5	33,460.1	25,162.7	23,406.8	29,088.3	30,559.5	28,368.4	24,395.9	265,236.6
Waste Coal	1,024.1	859.5	890.7	777.7	758.2	881.6	929.7	909.2	859.2	7,889.8
Nuclear	25,189.6	21,737.8	22,504.1	20,862.6	21,331.1	23,329.3	24,511.9	24,853.1	22,851.2	207,170.7
Gas	11,597.9	9,772.2	11,053.4	8,392.8	10,715.9	12,489.6	13,858.4	14,158.4	13,158.5	105,197.1
Natural Gas	11,377.7	9,566.6	10,845.4	8,185.5	10,508.5	12,274.2	13,636.6	13,946.3	12,933.9	103,274.6
Landfill Gas	207.0	181.3	194.5	197.3	206.4	196.4	199.7	206.4	197.6	1,786.6
Biomass Gas	13.2	24.3	13.5	10.1	1.0	19.0	22.1	5.7	27.1	136.0
Hydroelectric	1,391.3	1,074.4	1,371.9	1,448.9	1,575.4	1,380.0	1,231.6	1,257.5	870.1	11,601.1
Pumped Storage	536.0	530.6	551.0	433.3	606.2	794.5	832.8	857.0	600.7	5,742.0
Run of River	855.3	543.7	821.0	1,015.6	969.2	585.5	398.8	400.6	269.4	5,859.0
Wind	1,918.4	1,342.1	1,661.4	1,697.7	1,238.1	820.3	757.2	566.4	721.4	10,723.0
Waste	407.6	336.6	433.7	421.9	445.8	464.3	469.4	485.2	431.5	3,895.9
Solid Waste	324.2	270.0	342.0	350.6	375.0	381.9	391.8	391.3	364.6	3,191.3
Miscellaneous	83.4	66.6	91.7	71.3	70.8	82.4	77.6	93.8	66.9	704.6
Oil	840.7	69.2	199.3	31.8	173.6	250.2	541.0	463.5	243.6	2,812.9
Heavy Oil	585.2	39.0	132.2	25.1	145.4	231.1	510.2	449.1	233.6	2,351.0
Light Oil	193.4	28.7	64.4	6.4	27.8	18.6	30.1	11.7	9.0	390.2
Diesel	47.3	0.5	1.0	0.0	0.2	0.2	0.2	1.1	0.8	51.4
Kerosene	14.9	1.0	1.6	0.3	0.1	0.2	0.4	1.6	0.2	20.2
Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Solar	16.0	20.2	31.5	42.8	41.4	45.8	48.8	45.3	38.8	330.6
Battery	0.2	0.1	0.2	4.6	0.2	0.1	0.1	0.1	0.1	5.8
Total	79,195.1	69,197.7	71,606.3	58,843.5	59,686.5	68,749.5	72,907.5	71,107.0	63,570.3	614,863.3

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 4,934 MW, or 2.8 percent, from 175,960 MW in the first nine months of 2013 to 171,026 MW in the first nine months of 2014.[23] 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 nine months of 2014, 1,030 MW of new capacity were added to PJM. This new generation was more than offset by the deactivation of 12 units (1,526MW) since January 1, 2014. The decrease in offered supply in the first nine months of 2014 was in part a result of a 992.8 MW reduction in net capacity between October 2013 and September 2014.[24]

PJM average real-time generation in the first nine months of 2014 increased by 2.2 percent from the first nine months of 2013, from 90,432 MW to 92,449 MW. PJM average real-time generation in the first nine months of 2014 would

23 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.

24 The net capacity additions are calculated by taking the difference between the new generation (1,622 MW) and the retired generation (3,808 MW) after July 1, 2013.

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have increased by 1.4 percent from the first nine months of 2013, from 90,432 MW to 91,701 MW, if the EKPC Transmission Zone had not been included in the comparison.[25,26]

PJM average real-time supply, including imports, in the first nine months of 2014 increased by 2.4 percent from the first nine months of 2013, from 95,639 MW to 97,922 MW. PJM average real-time supply, including imports, in the first nine months of 2014 would have increased by 1.6 percent from the first nine months of 2013, from 95,639 MW to 97,175 MW, if the EKPC Transmission Zone had not been included in the comparison.

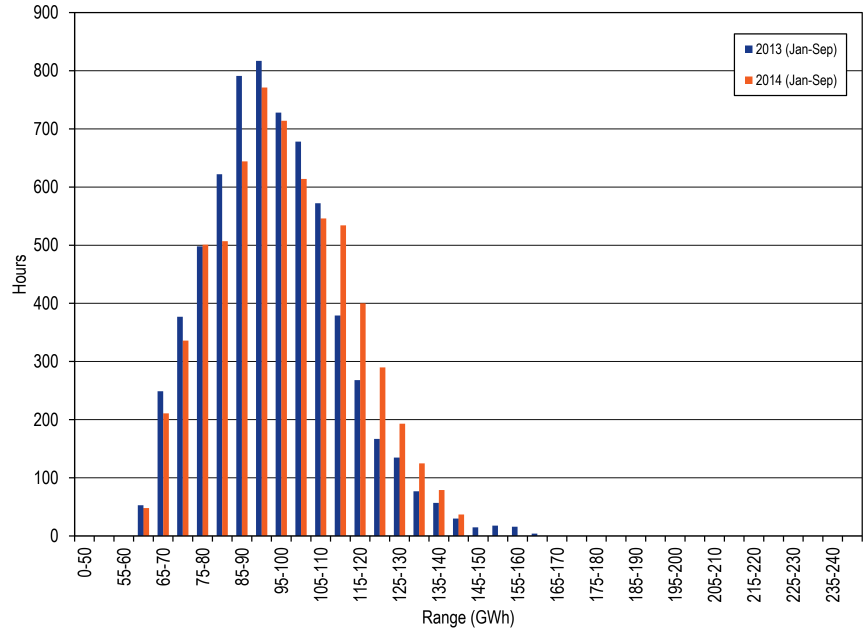
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **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 3-6 shows the hourly distribution of PJM real-time generation plus imports for the first nine months of 2013 and the first nine months of 2014.

Figure 3-6 Distribution of PJM real-time generation plus imports: January through September of 2013 and 2014[27]



25 The EKPC Transmission Zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013 and 2014.
26 Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

27 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 nine months of each year for the 15-year period from 2000 through 2014.[28]

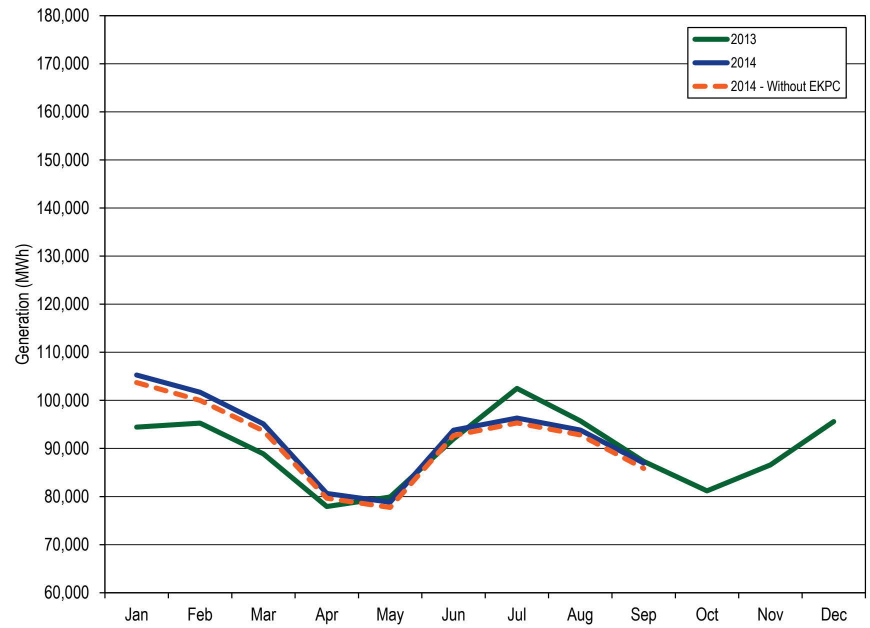
Table 3-10 PJM real-time average hourly generation and real-time average hourly generation plus average hourly imports: January through September of 2000 through 2014

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
(Jan-Sep)	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2000	30,989	5,216	33,855	5,966	NA	NA	NA	NA
2001	30,304	5,216	33,299	5,571	(2.2%)	0.0%	(1.6%)	(6.6%)
2002	34,467	8,217	38,207	8,540	13.7%	57.5%	14.7%	53.3%
2003	37,211	6,556	40,815	6,526	8.0%	(20.2%)	6.8%	(23.6%)
2004	45,888	11,035	49,990	11,185	23.3%	68.3%	22.5%	71.4%
2005	81,095	16,710	86,330	17,216	76.7%	51.4%	72.7%	53.9%
2006	84,260	14,696	88,621	15,399	3.9%	(12.1%)	2.7%	(10.5%)
2007	87,297	14,853	91,647	15,668	3.6%	1.1%	3.4%	1.7%
2008	85,241	14,203	90,621	14,646	(2.4%)	(4.4%)	(1.1%)	(6.5%)
2009	78,850	14,242	83,986	14,728	(7.5%)	0.3%	(7.3%)	0.6%
2010	84,086	16,346	88,876	17,001	6.6%	14.8%	5.8%	15.4%
2011	86,966	17,369	91,746	18,276	3.4%	6.3%	3.2%	7.5%
2012	90,367	16,893	95,726	17,810	3.9%	(2.7%)	4.3%	(2.5%)
2013	90,432	15,792	95,639	16,729	0.1%	(6.5%)	(0.1%)	(6.1%)
2014	92,449	16,002	97,922	17,064	2.2%	1.3%	2.4%	2.0%

PJM Real-Time, Monthly Average Generation

Figure 3-7 compares the real-time, monthly average hourly generation in 2013 to the first nine months of 2014 with and without EKPC.

Figure 3-7 PJM real-time average monthly hourly generation: January 2013 through September 2014



Day-Ahead Supply

PJM average day-ahead supply in the first nine months of 2014, including INCs and up-to congestion transactions, increased by 8.5 percent from the first nine months of 2013, from 148,489 MW to 161,137 MW. The PJM average day-ahead supply in the first nine months of 2014, including INCs and up-to congestion transactions, would have increased by 7.8 percent in the first nine months of 2014, from 148,489 MW to 160,078 MW, if the EKPC Transmission Zone had not been included in the comparison.

28 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.

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PJM average day-ahead supply in the first nine months of 2014, including INCs, up-to congestion transactions, and imports, increased by 8.4 percent from the first nine months of 2013, from 150,785 MW to 163,431 MW. PJM average day-ahead supply in the first nine months of 2014, including INCs, up-to congestion transactions, and imports, would have increased by 7.7 percent from the first nine months of 2013, from 150,785 MW to 162,373 MW, if the EKPC Transmission Zone had not been included in the comparison.

The day-ahead supply growth was 286.4 percent higher than the real-time generation growth in the first nine months of 2014, because of the continued growth, until September 8, 2014, of up-to congestion transactions. While up-to congestion transactions (UTC) continued to displace increment offers and decrement bids, there was a sharp decrease in UTCs in September as a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[29]

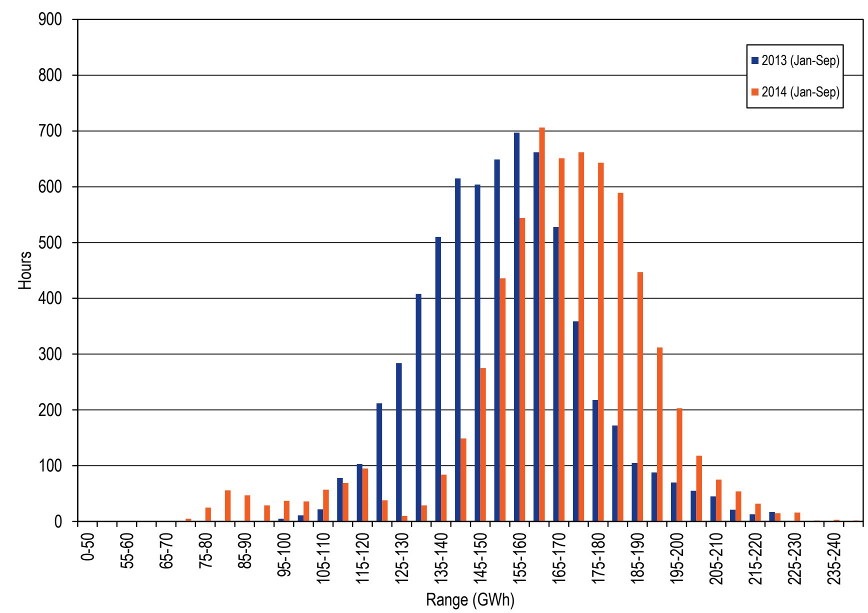
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **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 3-8 shows the hourly distribution of PJM day-ahead supply, including increment offers, up-to congestion transactions, and imports for the first nine months of 2013 and the first nine months of 2014.

Figure 3-8 Distribution of PJM day-ahead supply plus imports: January through September of 2013 and 2014[30]



29 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

30 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 nine months of each year of the 15-year period from 2000 through 2014.[31]

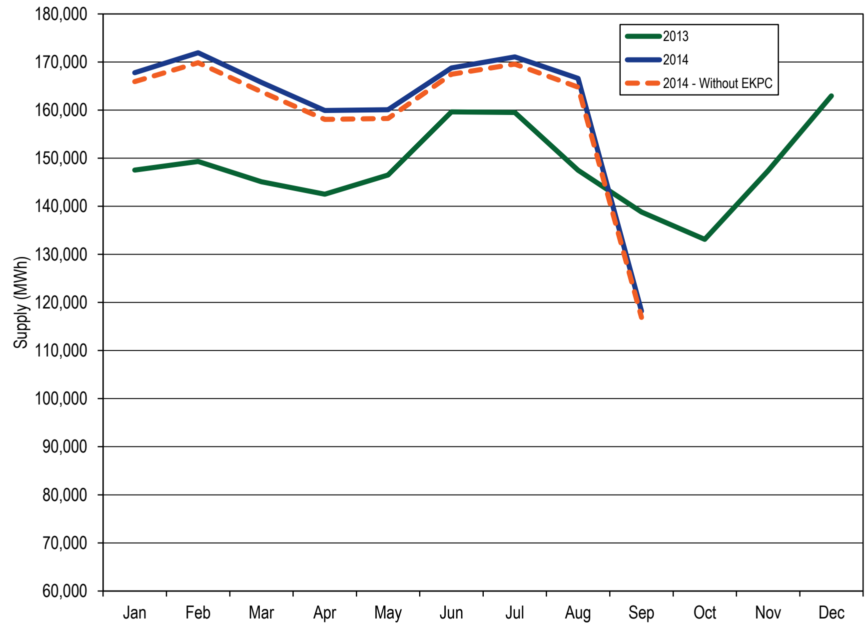
Table 3-11 PJM day-ahead average hourly supply and day-ahead average hourly supply plus average hourly imports: January through September of 2000 through 2014

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
(Jan-Sep)	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2000	27,853	5,340	28,233	5,395	NA	NA	NA	NA
2001	27,519	4,839	28,279	4,911	(1.2%)	(9.4%)	0.2%	(9.0%)
2002	30,080	10,982	30,629	10,992	9.3%	126.9%	8.3%	123.8%
2003	40,024	9,079	40,556	9,066	33.1%	(17.3%)	32.4%	(17.5%)
2004	56,103	13,380	56,799	13,349	40.2%	47.4%	40.0%	47.2%
2005	94,437	18,671	96,315	18,963	68.3%	39.5%	69.6%	42.1%
2006	100,888	18,061	103,029	18,071	6.8%	(3.3%)	7.0%	(4.7%)
2007	110,300	17,561	112,575	17,752	9.3%	(2.8%)	9.3%	(1.8%)
2008	107,367	16,601	109,811	16,717	(2.7%)	(5.5%)	(2.5%)	(5.8%)
2009	98,527	17,462	101,123	17,526	(8.2%)	5.2%	(7.9%)	4.8%
2010	108,309	23,295	111,059	23,464	9.9%	33.4%	9.8%	33.9%
2011	116,988	22,722	119,488	23,015	8.0%	(2.5%)	7.6%	(1.9%)
2012	135,213	18,553	137,670	18,788	15.6%	(18.3%)	15.2%	(18.4%)
2013	148,489	18,858	150,785	19,073	9.8%	1.6%	9.5%	1.5%
2014	161,137	23,922	163,431	24,080	8.5%	26.9%	8.4%	26.2%

PJM Day-Ahead, Monthly Average Supply

Figure 3-9 compares the day-ahead, monthly average hourly supply, including increment offers and up-to congestion transactions, in 2013 to the first nine months of 2014 with and without EKPC. The sharp decrease in UTC MW in September, which resulted in a corresponding decrease in day-ahead supply, was a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[32]

Figure 3-9 PJM day-ahead monthly average hourly supply: January 2013 through September 2014



Real-Time and Day-Ahead Supply

Table 3-12 presents summary statistics for the first nine months of 2013 and the first nine 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-ahead generation less the total physical real-time generation. In the first nine months of 2014, up-to congestion transactions were 38.2 percent of the total day-ahead supply compared to 33.7 percent in the first nine months of 2013.

31 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.

32 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

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

		Day Ahead					Real Time		Day Ahead Less Real Time	
	(Jan-Sep)	Generation	INC Offers	Up-to Congestion	Imports	Total Supply	Generation	Total Supply	Total Supply	Total Generation
Average	2013	92,323	5,279	50,888	2,295	150,785	90,432	95,639	55,145	1,891
	2014	95,427	3,359	62,351	2,294	163,431	92,449	97,922	65,509	2,978
Median	2013	91,378	5,292	51,045	2,259	150,598	89,341	94,099	56,499	2,037
	2014	94,776	3,226	65,651	2,268	166,097	91,287	96,679	69,418	3,489
Standard Deviation	2013	16,953	868	10,509	459	19,073	15,792	16,729	2,344	1,160
	2014	16,852	881	17,350	428	24,080	16,002	17,064	7,016	849
Peak Average	2013	102,879	5,551	51,272	2,384	162,086	99,804	105,581	56,505	3,075
	2014	105,800	3,828	62,347	2,463	174,438	101,790	107,959	66,479	4,010
Peak Median	2013	100,661	5,620	52,023	2,368	159,932	98,051	103,561	56,371	2,610
	2014	105,384	3,816	66,186	2,406	177,198	101,266	107,135	70,063	4,119
Peak Standard Deviation	2013	13,985	776	9,793	401	15,937	13,518	14,474	1,463	467
	2014	13,485	800	16,853	389	21,930	13,183	14,063	7,868	302
Off-Peak Average	2013	83,093	5,040	50,552	2,218	140,903	82,238	86,947	53,956	856
	2014	86,357	2,948	62,355	2,147	153,806	84,281	89,146	64,660	2,076
Off-Peak Median	2013	81,594	5,001	50,254	2,129	139,972	80,728	85,235	54,737	866
	2014	85,081	2,851	65,234	2,107	157,517	82,531	87,177	70,340	2,549
Off-Peak Standard Deviation	2013	13,604	874	11,087	491	15,828	12,797	13,396	2,432	808
	2014	14,034	731	17,776	405	21,630	13,603	14,414	7,216	431

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Figure 3-10 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 3-10 Day-ahead and real-time supply (Average hourly volumes): January through September of 2014

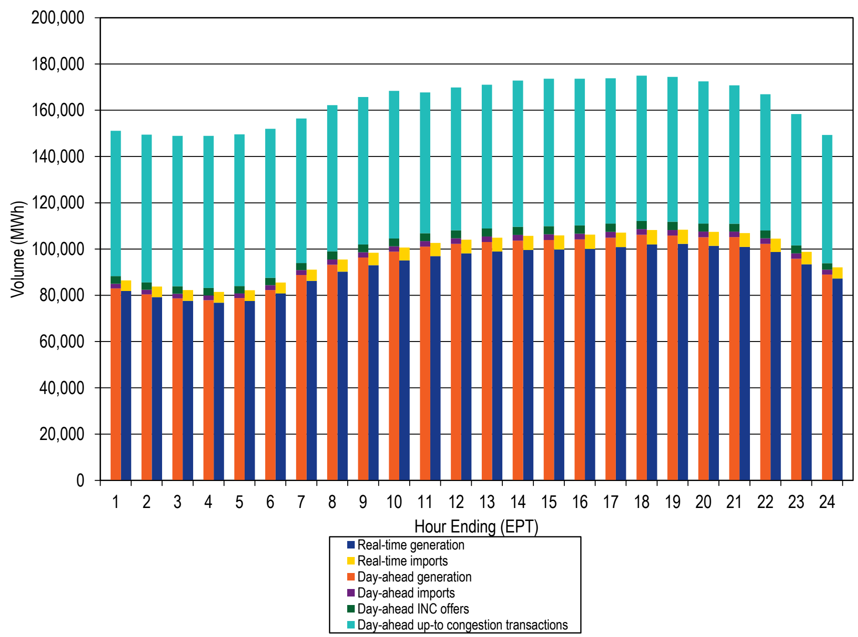

Figure 3-11 shows the difference between the day-ahead and real-time average daily supply in January 2013 through September of 2014.

Figure 3-11 Difference between day-ahead and real-time supply (Average daily volumes): January 2013 through September of 2014

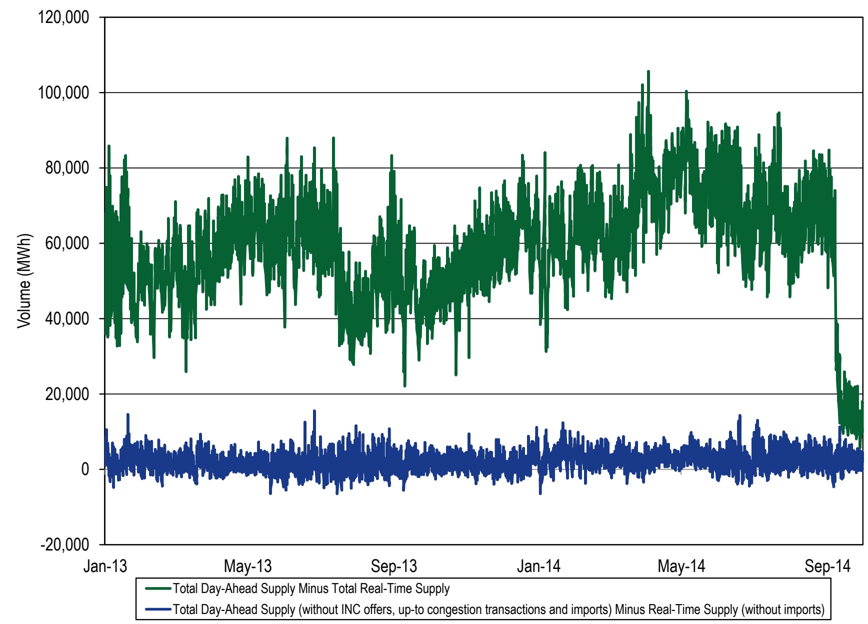

Figure 3-12 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2014. Table 3-13 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2013 and the first nine months of 2014. Figure 3-12 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.

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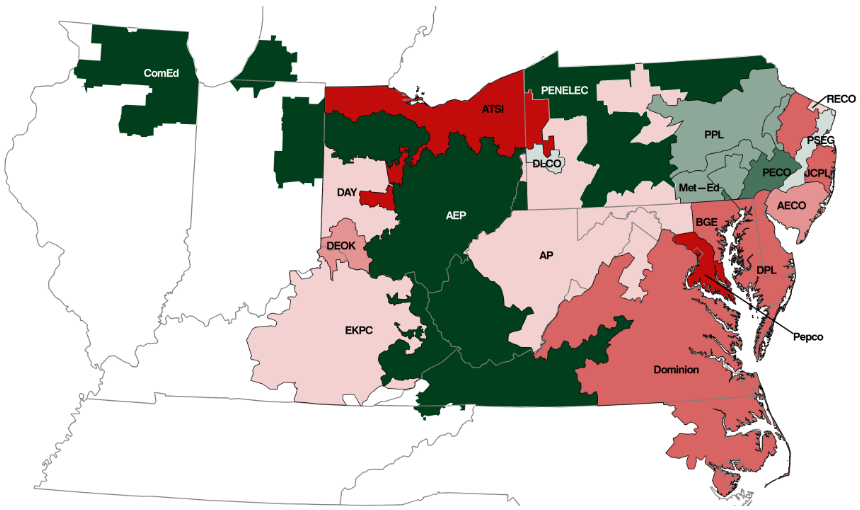
Figure 3-12 Map of PJM real-time generation less real-time load by zone: January through September of 2014[33]



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	(5,473)	ComEd	19,700	DPL	(8,316)	PENELEC	21,486
AEP	18,520	DAY	(1,759)	EKPC	(1,595)	Pepco	(13,865)
AP	(2,032)	DEOK	(5,908)	JCPL	(7,790)	PPL	6,562
ATSI	(10,979)	DLCO	2,042	Met-Ed	4,935	PSEG	729
BGE	(8,067)	Dominion	(9,990)	PECO	15,277	RECO	(1,148)

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

	Zonal Generation and Load (GWh)					
	2013 (Jan - Sep)			2014 (Jan - Sep)		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	1,720.2	8,013.9	(6,293.7)	2,450.0	7,922.8	(5,472.8)
AEP	99,790.3	97,582.4	2,207.9	115,730.6	97,210.9	18,519.7
AP	42,595.9	35,282.2	7,313.7	34,345.1	36,376.7	(2,031.6)
ATSI	41,393.9	50,220.1	(8,826.2)	40,304.0	51,283.2	(10,979.2)
BGE	15,944.6	24,500.6	(8,556.0)	16,464.0	24,530.5	(8,066.5)
ComEd	94,423.0	74,585.7	19,837.4	94,155.0	74,455.2	19,699.8
DAY	12,891.4	12,587.0	304.4	11,122.1	12,881.1	(1,759.0)
DEOK	18,602.4	20,209.2	(1,606.8)	14,713.6	20,621.5	(5,907.9)
DLCO	13,962.7	11,109.6	2,853.1	13,073.4	11,031.7	2,041.8
Dominion	61,604.3	71,237.2	(9,633.0)	62,805.2	72,795.6	(9,990.4)
DPL	5,874.7	14,084.8	(8,210.2)	5,729.5	14,045.1	(8,315.6)
EKPC	3,420.7	3,937.2	(516.5)	8,030.0	9,624.9	(1,594.9)
JCPL	8,523.9	17,636.1	(9,112.2)	9,677.0	17,466.6	(7,789.6)
Met-Ed	15,490.1	11,332.1	4,158.0	16,395.7	11,460.4	4,935.4
PECO	45,148.4	30,480.7	14,667.8	45,657.6	30,380.1	15,277.4
PENELEC	32,773.1	12,889.7	19,883.4	34,448.5	12,962.8	21,485.8
Pepco	6,993.3	23,260.3	(16,266.9)	9,555.6	23,421.0	(13,865.5)
PPL	36,462.3	30,328.6	6,133.7	37,387.9	30,825.7	6,562.2
PSEG	34,804.9	33,390.7	1,414.2	33,586.9	32,857.8	729.1
RECO	0.0	1,177.6	(1,177.6)	0.0	1,148.2	(1,148.2)

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 nine months of 2014 was 141,673 MW in the HE 1700 on June 17, 2014, which was 15,835 MW, or 10.1 percent, lower than the peak load for the first nine months of 2013, which

33 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/markets-and-operations/energy/lmp-model-info/bus-model-updates.aspx>. (Accessed on 10/8/2014)

was 157,508 MW in the HE 1700 on July 18, 2013. The EKPC Transmission Zone accounted for 2,128 MW in the peak hour of the first nine months of 2014. The peak load excluding the EKPC Transmission Zone was 139,545 MW, also occurring on June 17, 2014, HE 1700, a decrease of 17,964 MW, or 11.4 percent from the first nine months of 2013.

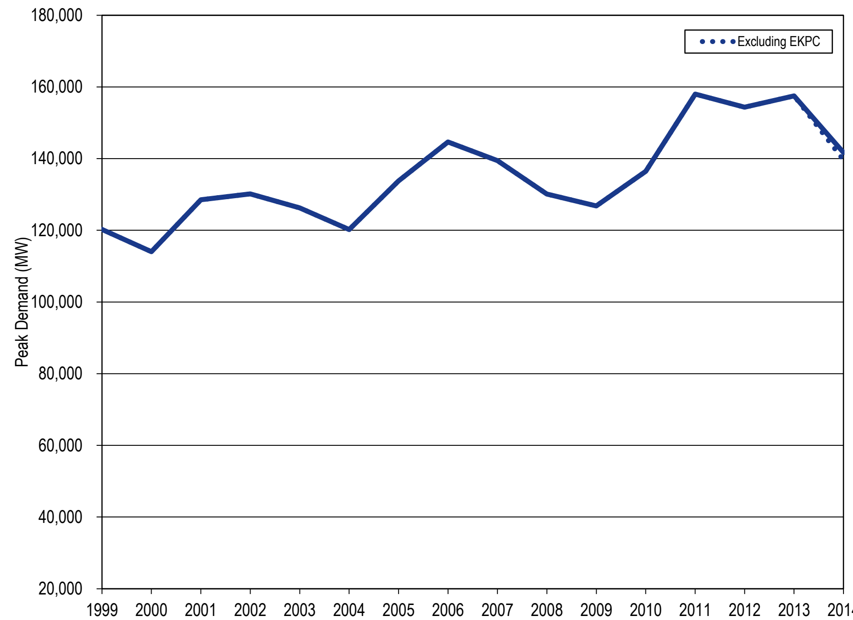
Table 3-14 shows the peak loads for the first nine months of the years 1999 through 2014.

Table 3-14 Actual PJM footprint peak loads: January through September of 1999 to 2014[34]

(Jan - Sep)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Fri, July 30	17	120,227	NA	NA
2000	Wed, August 09	17	114,036	(6,191)	(5.1%)
2001	Wed, August 08	17	128,535	14,499	12.7%
2002	Thu, August 01	17	130,159	1,625	1.3%
2003	Thu, August 21	17	126,259	(3,900)	(3.0%)
2004	Wed, June 09	17	120,218	(6,041)	(4.8%)
2005	Tue, July 26	16	133,761	13,543	11.3%
2006	Wed, August 02	17	144,644	10,883	8.1%
2007	Wed, August 08	16	139,428	(5,216)	(3.6%)
2008	Mon, June 09	17	130,100	(9,328)	(6.7%)
2009	Mon, August 10	17	126,798	(3,302)	(2.5%)
2010	Tue, July 06	17	136,460	9,662	7.6%
2011	Thu, July 21	17	158,016	21,556	15.8%
2012	Tue, July 17	17	154,344	(3,672)	(2.3%)
2013	Thu, July 18	17	157,508	3,165	2.1%
2014 (with EKPC)	Tue, June 17	17	141,673	(15,835)	(10.1%)
2014 (without EKPC)	Tue, June 17	17	139,545	(17,964)	(11.4%)

Figure 3-13 shows the peak loads for the first nine months of the years 1999 through 2014.

Figure 3-13 PJM footprint calendar year peak loads: January through September of 1999 to 2014



34 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>.

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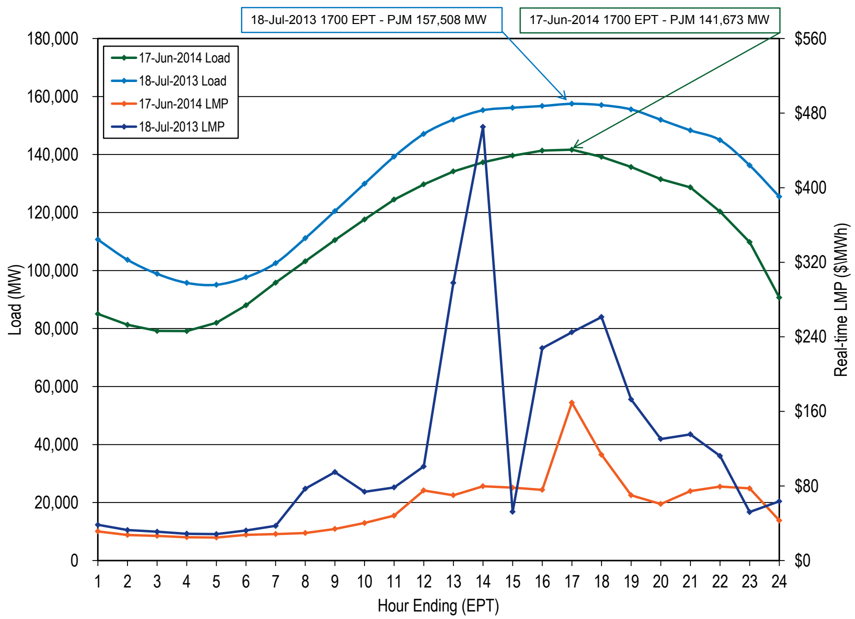
Figure 3-14 compares the peak load days in the first nine months of 2013 and the first nine months of 2014. The average hourly real-time LMP peaked at $169.33 on June 17, 2014 and peaked at $465.18 on July 18, 2013.

Figure 3-14 PJM peak-load comparison: Tuesday, June 17, 2014, and Tuesday, July 18, 2013



Real-Time Demand

PJM average real-time load in the first nine months of 2014 increased by 1.6 percent from the first nine months of 2013, from 89,123 MW to 90,567 MW. PJM average real-time load in the first nine months of 2014 would have increased by 0.7 percent from the first nine months of 2013, from 89,123 MW to 89,707 MW, if the EKPC Transmission Zone had not been included in the comparison.[35,36]

35 The EKPC Transmission Zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013 and 2014.

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

PJM average real-time demand in the first nine months of 2014 increased 2.5 percent from the first nine months of 2013, from 93,647 MW to 96,015 MW. PJM average real-time demand in the first nine months of 2014 would have increased by 1.6 percent from the first nine months of 2013, from 93,647 MW to 95,155 MW, if the EKPC Transmission Zone had not been included in the comparison.

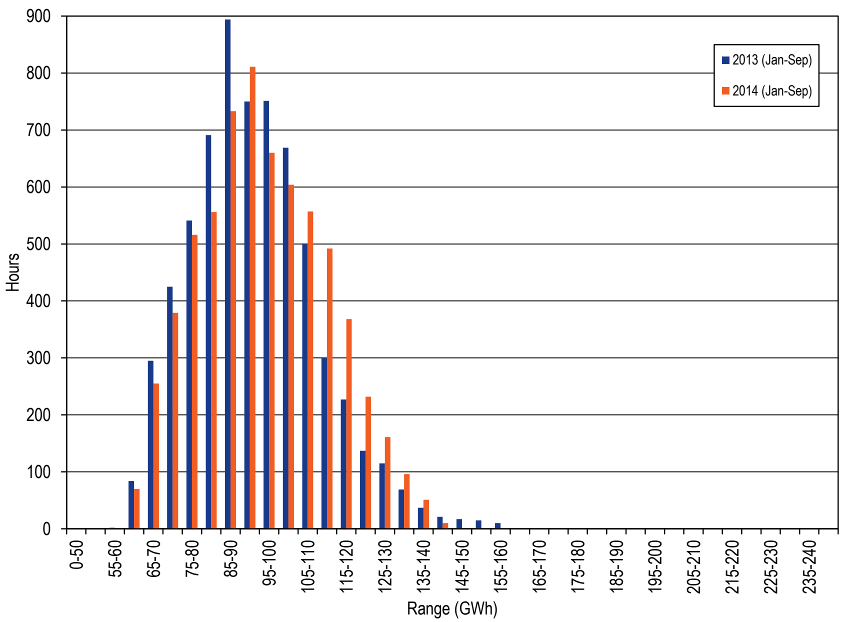
In the PJM Real-Time Energy Market, there are two types of demand:

- **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 3-15 shows the hourly distribution of PJM real-time load plus exports for the first nine months of 2013 and the first nine months of 2014.[37]

Figure 3-15 Distribution of PJM real-time accounting load plus exports: January through September of 2013 and 2014[38]



PJM Real-Time, Average Load

Table 3-15 presents summary real-time demand statistics for the first nine 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.[39]

Table 3-15 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: January through September of 1998 through 2014[40]

	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
(Jan-Sep)	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
1998	29,112	5,780	29,112	5,780	NA	NA	NA	NA
1999	30,236	6,306	30,236	6,306	3.9%	9.1%	3.9%	9.1%
2000	30,266	5,765	31,060	5,977	0.1%	(8.6%)	2.7%	(5.2%)
2001	31,060	6,156	32,900	5,861	2.6%	6.8%	5.9%	(2.0%)
2002	35,715	8,688	37,367	8,878	15.0%	41.1%	13.6%	51.5%
2003	37,996	7,187	39,965	7,120	6.4%	(17.3%)	7.0%	(19.8%)
2004	45,294	10,512	49,176	11,556	19.2%	46.3%	23.0%	62.3%
2005	78,235	17,541	85,295	17,794	72.7%	66.9%	73.4%	54.0%
2006	80,717	15,568	87,326	16,147	3.2%	(11.2%)	2.4%	(9.3%)
2007	83,114	15,386	89,390	16,008	3.0%	(1.2%)	2.4%	(0.9%)
2008	80,611	14,389	87,788	14,893	(3.0%)	(6.5%)	(1.8%)	(7.0%)
2009	76,954	13,879	82,118	14,360	(4.5%)	(3.5%)	(6.5%)	(3.6%)
2010	81,068	16,209	86,994	16,687	5.3%	16.8%	5.9%	16.2%
2011	83,762	17,604	89,628	17,799	3.3%	8.6%	3.0%	6.7%
2012	88,687	17,431	93,763	17,329	5.9%	(1.0%)	4.6%	(2.6%)
2013	89,123	16,384	93,647	16,254	0.5%	(6.0%)	(0.1%)	(6.2%)
2014	90,567	16,662	96,015	16,518	1.6%	1.7%	2.5%	1.6%

37 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>.

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

39 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.

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

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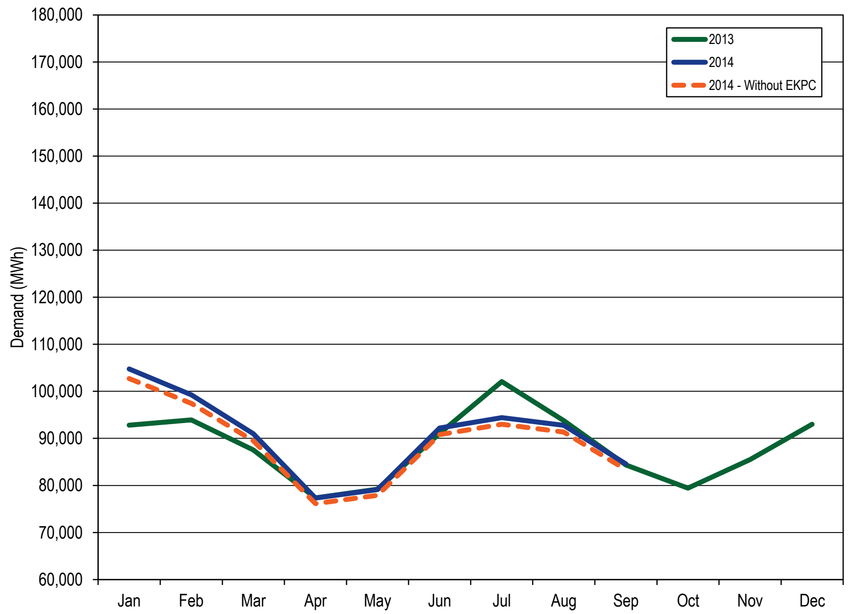
PJM Real-Time, Monthly Average Load

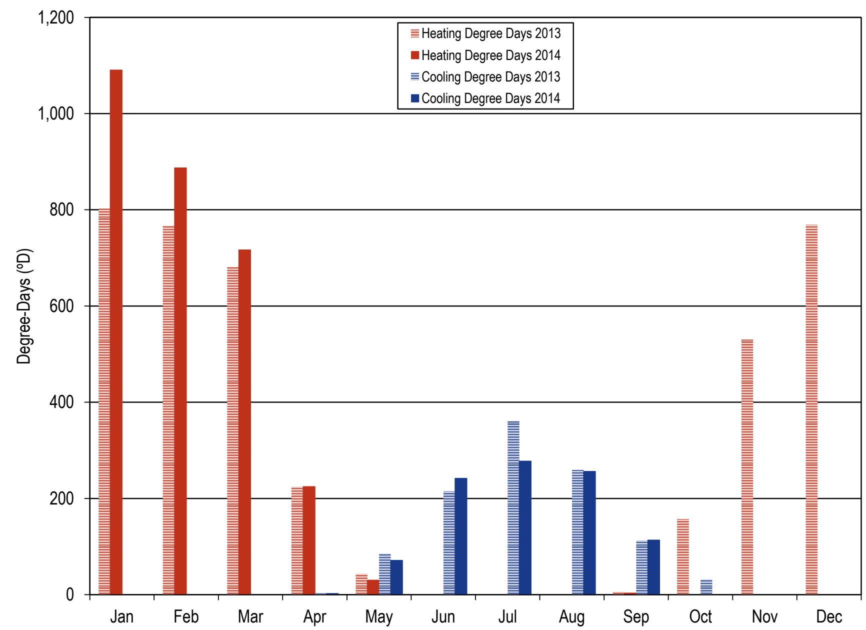
Figure 3-16 compares the real-time, monthly average hourly loads in 2013 to the first nine months of 2014 with and without EKPC.

Figure 3-16 PJM real-time monthly average hourly load: January 2013 through September 2014



PJM real-time load is significantly affected by temperature. Figure 3-17 and Table 3-16 compare the PJM monthly heating and cooling degree days in the first nine months of 2014 with those in the first nine months of 2013.[41] The figure and table show that in 2014, the heating degree days increased 35.8 percent in January, increased 15.6 percent in February, increased 5.2 percent in March, remained constant in April, decreased 31.1 percent in May, and decreased 47.2 percent in September compared to 2013. The figure shows that in 2014, the cooling degree days decreased 20.5 percent in April, decreased 16.7 percent in May, increased 12.5 percent in June, decreased 23.2 percent in July, decreased 1.2 percent in August, and increased 0.5 percent in September compared to 2013.

Figure 3-17 PJM heating and cooling degree days: January 2013 through September 2014



41 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.

Table 3-16 PJM heating and cooling degree days: January 2013 through September 2014

	2013		2014	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	803	0	1,090	0
Feb	767	0	887	0
Mar	681	0	716	0
Apr	224	3	224	2
May	43	86	30	71
Jun	0	215	0	242
Jul	0	361	0	277
Aug	0	259	0	256
Sep	6	113	3	113
Oct	157	32		
Nov	530	0		
Dec	769	0		
Total	3,982	1,069	2,951	962

Day-Ahead Demand

PJM average day-ahead demand in the first nine months of 2014, including DECs and up-to congestion transactions, increased by 7.9 percent from the first nine months of 2013, from 145,139 MW to 156,542 MW. The PJM average day-ahead demand in the first nine months of 2014, including DECs and up-to congestion transactions, would have increased 7.1 percent from the first nine months of 2013, from 145,139 MW to 155,420 MW, if the EKPC Transmission Zone had not been included in the comparison.

PJM average day-ahead demand in the first nine months of 2014, including DECs, up-to congestion transactions, and exports, increased by 8.1 percent from the first nine months of 2013, from 148,444 MW to 160,425 MW. The PJM average day-ahead demand in the first nine months of 2014, including DECs and up-to congestion transactions, and imports, would have increased 7.3 percent from the first nine months of 2013, from 148,444 MW to 159,303 MW, if the EKPC Transmission Zone had not been included in the comparison.

The day-ahead demand growth was 393.8 percent higher than the real-time load growth in the first nine months of 2014, because of the continued growth, until September 8, 2014, of up-to congestion transactions. While up-to congestion transactions (UTC) continued to displace increment offers and decrement bids, there was a sharp decrease in UTCs in September as a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[42]

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.

42 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

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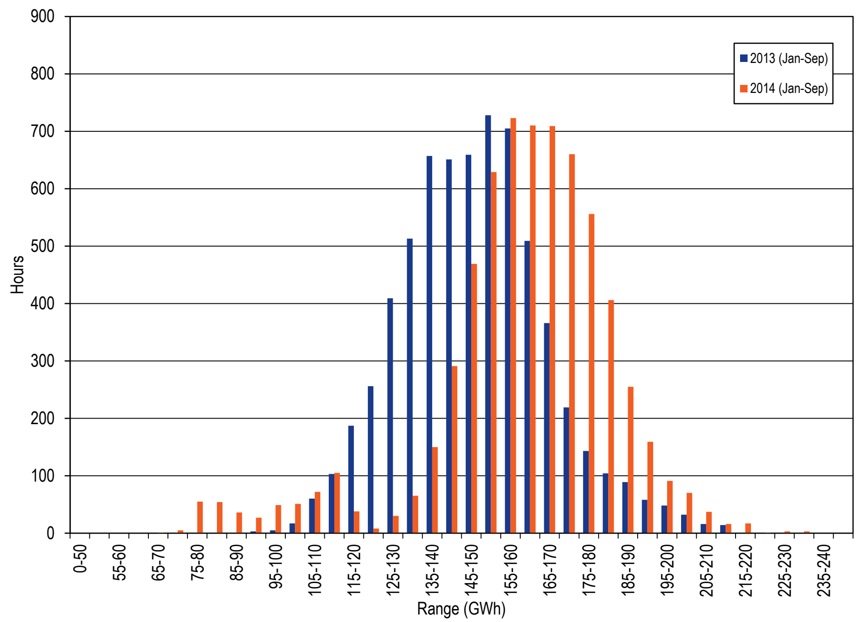
PJM Day-Ahead Demand Duration

Figure 3-18 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up-to congestion transactions, and exports for the first nine months of 2013 and the first nine months of 2014.

Figure 3-18 Distribution of PJM day-ahead demand plus exports: January through September of 2013 and 2014[43]



PJM Day-Ahead, Average Demand

Table 3-17 presents summary day-ahead demand statistics for the first nine months of each year of the 15-year period 2000 to 2014.[44]

Table 3-17 PJM day-ahead average demand and day-ahead average hourly demand plus average hourly exports: January through September of 2000 through 2014

	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
(Jan-Sep)	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2000	34,064	7,649	34,268	7,553	NA	NA	NA	NA
2001	33,944	7,016	34,444	6,817	(0.4%)	(8.3%)	0.5%	(9.7%)
2002	41,634	11,073	41,726	11,120	22.7%	57.8%	21.1%	63.1%
2003	45,371	8,377	45,477	8,354	9.0%	(24.4%)	9.0%	(24.9%)
2004	55,830	13,319	56,558	13,753	23.1%	59.0%	24.4%	64.6%
2005	93,525	19,126	96,302	19,455	67.5%	43.6%	70.3%	41.5%
2006	99,403	18,165	102,520	18,687	6.3%	(5.0%)	6.5%	(3.9%)
2007	107,295	17,580	110,711	17,949	7.9%	(3.2%)	8.0%	(4.0%)
2008	103,586	16,618	107,169	16,810	(3.5%)	(5.5%)	(3.2%)	(6.3%)
2009	96,020	16,995	99,084	17,117	(7.3%)	2.3%	(7.5%)	1.8%
2010	105,018	22,972	109,113	23,286	9.4%	35.2%	10.1%	36.0%
2011	113,724	22,444	117,533	22,651	8.3%	(2.3%)	7.7%	(2.7%)
2012	132,494	18,115	135,840	18,235	16.5%	(19.3%)	15.6%	(19.5%)
2013	145,139	18,667	148,444	18,696	9.5%	3.1%	9.3%	2.5%
2014	156,542	23,584	160,425	23,533	7.9%	26.3%	8.1%	25.9%

PJM Day-Ahead, Monthly Average Demand

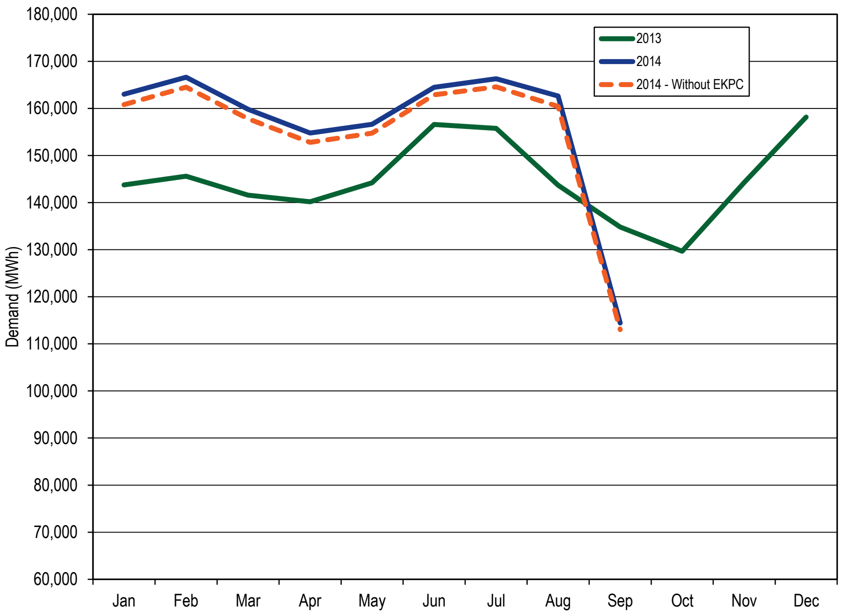
Figure 3-19 compares the day-ahead, monthly average hourly demand, including decrement bids and up-to congestion transactions, in 2013 to the first nine months of 2014 with and without EKPC. The sharp decrease in UTC MW in September, which resulted in a corresponding decrease in day-ahead demand, was a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[45]

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

44 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.

45 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

Figure 3-19 PJM day-ahead monthly average hourly demand: January 2013 through September 2014



Real-Time and Day-Ahead Demand

Table 3-18 presents summary statistics for the first nine months of 2013 and the first nine months of 2014 day-ahead and real-time demand. The last two columns of Table 3-18 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.

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Table 3-18 Cleared day-ahead and real-time demand (MWh): January through September of 2013 and 2014

		Day Ahead						Real Time		Day Ahead Less Real Time	
	(Jan-Sep)	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Total Demand	Total Load
Average	2013	85,893	1,156	7,204	50,888	3,304	148,444	89,123	93,647	54,797	(2,075)
	2014	86,518	1,240	6,432	62,351	3,883	160,425	90,567	96,015	64,410	(2,808)
Median	2013	84,729	1,184	6,925	51,045	3,242	148,180	87,586	92,198	55,982	(1,674)
	2014	85,321	1,229	6,148	65,651	3,779	162,809	88,957	94,758	68,051	(2,407)
Standard Deviation	2013	15,592	254	1,505	10,509	617	18,696	16,384	16,254	2,442	(537)
	2014	15,755	171	1,471	17,350	974	23,533	16,662	16,518	7,015	(735)
Peak Average	2013	95,790	1,248	7,956	51,272	3,272	159,538	99,025	103,333	56,205	(1,987)
	2014	96,415	1,317	7,228	62,347	3,869	171,177	100,493	105,782	65,395	(2,760)
Peak Median	2013	93,964	1,306	7,582	52,023	3,214	157,641	97,004	101,357	56,284	(1,734)
	2014	95,721	1,318	7,026	66,186	3,806	173,802	99,462	104,973	68,830	(2,423)
Peak Standard Deviation	2013	12,954	272	1,467	9,793	616	15,624	13,993	14,055	1,569	(767)
	2014	12,725	159	1,441	16,853	965	21,487	13,807	13,611	7,876	(923)
Off-Peak Average	2013	77,238	1,075	6,546	50,552	3,332	138,743	80,465	85,178	53,565	(2,152)
	2014	77,865	1,173	5,735	62,355	3,895	151,023	81,887	87,475	63,548	(2,849)
Off-Peak Median	2013	75,784	1,104	6,308	50,254	3,277	137,872	78,761	83,553	54,319	(1,874)
	2014	76,074	1,168	5,515	65,234	3,771	154,557	79,619	85,595	68,962	(2,377)
Off-Peak Standard Deviation	2013	12,184	206	1,199	11,087	615	15,493	13,087	12,990	2,503	(698)
	2014	12,775	152	1,096	17,776	981	21,095	13,865	13,897	7,198	(938)

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Figure 3-20 shows the average hourly cleared volumes of day-ahead demand and real-time demand. The day-ahead demand includes day-ahead load, day-ahead exports, decrement bids and up-to congestion transactions. The real-time demand includes real-time load and real-time exports.

Figure 3-20 Day-ahead and real-time demand (Average hourly volumes): January through September of 2014

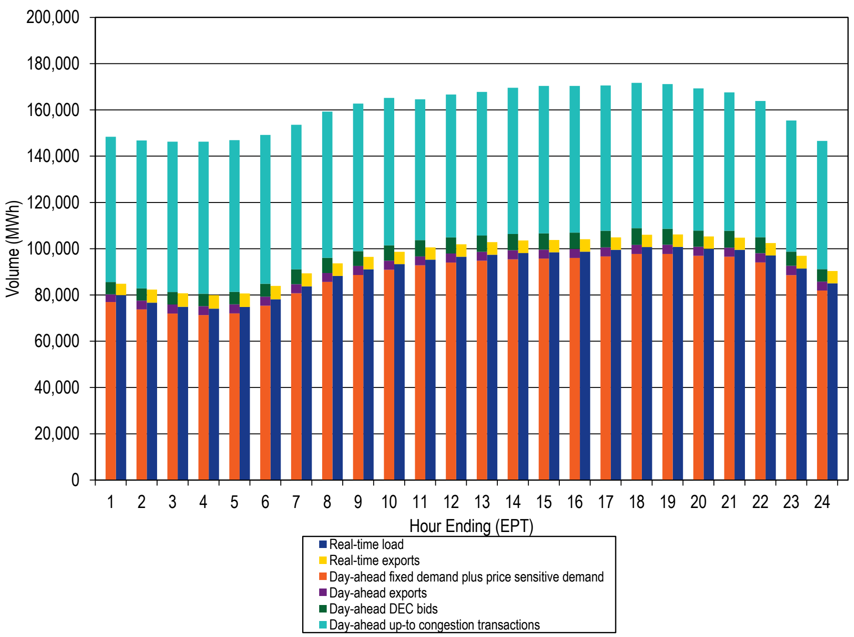
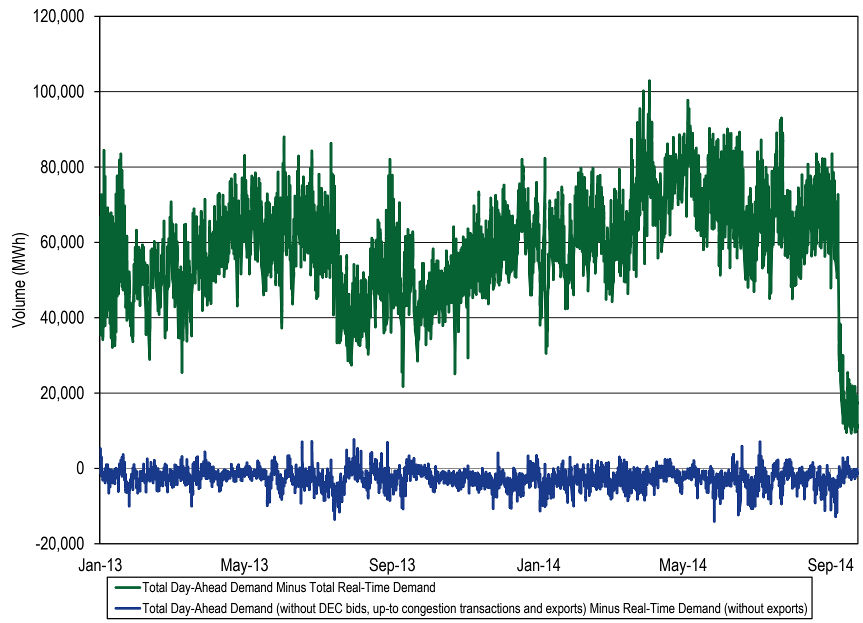


Figure 3-21 shows the difference between the day-ahead and real-time average daily demand in January 2013 through September 2014. The sharp decrease in UTC MW in September, which resulted in a corresponding decrease in day-ahead demand, was a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[46]

46 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

Figure 3-21 Difference between day-ahead and real-time demand (Average daily volumes): January 2013 through September 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).

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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 3-19 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 nine months of 2014, 10.2 percent of real-time load was supplied by bilateral contracts, 27.4 percent by spot market purchase and 62.5 percent by self-supply. Compared with 2013, reliance on bilateral contracts decreased 0.4 percentage points, reliance on spot supply increased by 2.4 percentage points and reliance on self-supply decreased by 1.9 percentage points.

Table 3-19 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%	9.1%	29.7%	61.2%	(1.6%)	5.5%	(3.9%)
May	10.9%	25.4%	63.6%	9.7%	28.8%	61.5%	(1.2%)	3.4%	(2.1%)
Jun	10.7%	25.0%	64.3%	10.6%	29.0%	60.4%	(0.1%)	4.0%	(3.8%)
Jul	10.2%	25.2%	64.7%	11.2%	25.7%	63.1%	1.0%	0.6%	(1.6%)
Aug	10.2%	24.5%	65.3%	11.2%	25.4%	63.4%	1.0%	0.9%	(1.9%)
Sep	10.1%	24.2%	65.7%	11.2%	25.6%	63.2%	1.1%	1.3%	(2.4%)
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%	10.2%	27.4%	62.5%	(0.4%)	2.4%	(1.9%)

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 3-20 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 nine months of 2014, 9.1 percent of day-ahead demand was supplied by bilateral contracts, 26.9 percent by spot market purchases, and 64.0 percent by self-supply. Compared with 2013, reliance on bilateral contracts increased by 1.0

percentage points, reliance on spot supply increased by 2.4 percentage points, and reliance on self-supply decreased by 3.4 percentage points.

Table 3-20 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%	7.9%	29.9%	62.3%	0.7%	6.8%	(7.6%)
May	7.8%	23.5%	68.7%	8.0%	29.0%	63.0%	0.2%	5.5%	(5.7%)
Jun	8.2%	23.8%	68.0%	9.4%	28.5%	62.1%	1.2%	4.7%	(5.9%)
Jul	8.0%	24.1%	67.9%	9.6%	25.1%	65.3%	1.6%	1.0%	(2.6%)
Aug	8.1%	23.9%	68.0%	9.7%	24.5%	65.8%	1.6%	0.6%	(2.2%)
Sep	7.8%	23.9%	68.3%	9.3%	24.9%	65.8%	1.6%	1.0%	(2.6%)
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%	9.1%	26.9%	64.0%	1.0%	2.4%	(3.4%)

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 3-21. The offer capping percentages shown in Table 3-21 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, due to an increase in constrained hours, 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. In the first nine months of 2014, the percentage of hours in which black start and reactive service units were economic increased compared to the first nine months of 2013 and the percentage of hours they were committed as offer capped decreased as a result.

Table 3-21 Offer-capping statistics – Energy only: January through September, 2010 to 2014

	Real Time		Day Ahead	
(Jan-Sep)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2010	1.2%	0.3%	0.3%	0.1%
2011	0.7%	0.3%	0.0%	0.0%
2012	1.1%	0.6%	0.1%	0.1%
2013	0.4%	0.1%	0.2%	0.0%
2014	0.5%	0.2%	0.2%	0.1%

Table 3-22 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. This trend reversed in the first nine months of 2014 because higher LMPs resulted in the increased economic dispatch of black start and reactive service resources.

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Table 3-22 Offer-capping statistics for energy and reliability: January through September, 2010 to 2014

	Real Time		Day Ahead	
(Jan-Sep)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2010	1.2%	0.3%	0.3%	0.1%
2011	1.5%	0.6%	0.0%	0.0%
2012	1.4%	0.8%	0.2%	0.2%
2013	2.9%	2.3%	3.2%	2.1%
2014	0.8%	0.6%	0.5%	0.4%

Table 3-23 presents data on the frequency with which units were offer capped in the first nine months of 2013 and the first nine months of 2014, for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market.

Table 3-23 Real-time offer-capped unit statistics: January through September, 2013 and 2014

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	(Jan - Sep)	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	0
	2013	0	0	0	0	0	0
80% and < 90%	2014	0	1	1	0	2	0
	2013	0	0	0	1	1	1
75% and < 80%	2014	1	1	0	0	1	0
	2013	0	0	0	1	1	3
70% and < 75%	2014	0	0	0	0	1	0
	2013	0	0	0	0	0	3
60% and < 70%	2014	0	0	0	0	6	4
	2013	0	0	0	0	0	6
50% and < 60%	2014	0	0	0	0	3	8
	2013	0	0	0	0	0	9
25% and < 50%	2014	0	0	9	1	10	43
	2013	0	0	6	0	5	50
10% and < 25%	2014	0	0	0	1	8	42
	2013	2	0	0	0	3	45

Table 3-23 shows that four units were offer capped for 80 percent or more of their run hours in the first nine months of 2014 compared to three units in the first nine months of 2013.

Offer Capping for Local Market Power

In the first nine months of 2014, the AEP, AP, ATSI, BGE, ComEd, DLCO, Dominion, DPL, PECO, PENELEC, Pepco, PPL and PSEG control zones experienced congestion resulting from one or more constraints binding for 75 or more hours. The AECO, DAY, DEOK, EKPC, JCPL, Met-Ed and RECO control zones did not have constraints binding for 75 or more hours in the first nine months of 2014. Table 3-24 shows that AEP, BGE, ComEd, Dominion, PPL, and PSEG were the only control zones with 75 or more hours of congestion or with an interface constraint that was binding for one or more hours in every year in the first nine months of 2009 through 2014. In the first nine months of 2014, the BGE Pepco interface (BCPEP) constraint was binding in Pepco for 41 hours.

Table 3-24 Numbers of hours when control zones experienced congestion for 75 or more hours: January through September, 2009 through 2014

	2009 (Jan - Sep)	2010 (Jan - Sep)	2011 (Jan - Sep)	2012 (Jan - Sep)	2013 (Jan - Sep)	2014 (Jan - Sep)
AECO	149	163	234	NA	NA	NA
AEP	1,005	975	2,197	178	1,210	1,474
AP	1,297	3,344	1,805	89	NA	170
ATSI	140	NA	NA	208	68	481
BGE	127	274	368	1,582	1,192	4,416
ComEd	784	2,108	872	1,808	3,169	1,928
DEOK	NA	NA	NA	185	NA	NA
DLCO	156	393	NA	209	NA	223
Dominion	456	889	1,593	559	1,148	179
DPL	NA	111	NA	382	783	542
Met-Ed	NA	168	NA	NA	NA	NA
PECO	247	NA	276	NA	390	1,826
PENELEC	80	96	77	NA	NA	2,147
Pepco	149	NA	76	143	200	41
PPL	176	117	40	146	609	148
PSEG	379	515	1,132	259	1,993	2,132

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The local market structure in the Real-Time Energy Market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results for the first nine months of 2014.[47] The three pivotal supplier (TPS) test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. Only uncommitted resources, which would be started to relieve the transmission constraint, are subject to offer capping. Already committed units that can provide incremental relief cannot be offer capped. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small.

Table 3-25 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 3-25 Three pivotal supplier test details for interface constraints: January through September, 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	379	373	13	1	12
	Off Peak	396	399	12	1	11
AEP - DOM	Peak	376	254	8	0	8
	Off Peak	323	211	7	0	7
AP South	Peak	398	464	9	0	9
	Off Peak	427	517	9	0	9
BC/PEPCO	Peak	582	585	7	0	6
	Off Peak	482	468	6	0	6
Bedington - Black Oak	Peak	162	191	13	3	10
	Off Peak	200	163	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
Western	Peak	951	887	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 3-26 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.

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

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Table 3-26 Summary of three pivotal supplier tests applied for interface constraints: January through September, 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	991	84	8%	8	1%	10%
	Off Peak	887	82	9%	2	0%	2%
AEP - DOM	Peak	79	5	6%	0	0%	0%
	Off Peak	238	29	12%	0	0%	0%
AP South	Peak	4607	189	4%	2	0%	1%
	Off Peak	3546	176	5%	4	0%	2%
BC/PEPCO	Peak	246	26	11%	0	0%	0%
	Off Peak	112	8	7%	0	0%	0%
Bedington - Black Oak	Peak	1201	106	9%	13	1%	12%
	Off Peak	358	39	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%
Western	Peak	1158	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.[48] The markup index is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost. The markup index does not measure the impact of unit markup on total LMP.

Real-Time Markup

Table 3-27 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 nine months of 2014, 73.9 percent of marginal units had average dollar markups less than zero and 73.9 percent of units had 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. Using the unadjusted cost offers, the highest markup in the first nine months of 2014 was $922.3 whereas the highest markup in the first nine months of 2013 was $ 355.9.

48 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.

Table 3-27 Average, real-time marginal unit markup index (By offer price category): January through September 2013 and 2014

	2013 (Jan - Sep)			2014 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.02	($3.25)	21.4%	(0.10)	($2.18)	16.5%
$25 to $50	(0.01)	($1.25)	62.5%	(0.01)	($1.14)	57.4%
$50 to $75	0.01	($1.53)	8.6%	0.05	$2.12	8.6%
$75 to $100	0.06	$3.41	1.5%	0.10	$8.01	2.5%
$100 to $125	0.13	$13.66	0.7%	0.04	$3.72	4.8%
$125 to $150	0.09	$11.51	0.8%	0.11	$13.78	1.2%
>= $150	0.04	$9.33	4.5%	0.09	$22.16	9.0%

Day-Ahead Markup

Table 3-28 shows the average markup index of marginal units in Day-Ahead Energy Market, by offer price category. In the first nine months of 2014, 94.8 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.02. 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 nine months of 2013, to 0.14 in the first nine months of 2014 in the offer price category from $100 to $125. There were five hours when the generating resources had offer prices of $100 or above in the first nine months of 2013. However, in the first nine months of 2014, there were 442 hours when the marginal units had offer prices of $100 or above and the highest markup was $392 per MWh.

Table 3-28 Average day-ahead marginal unit markup index (By offer price category): January through September of 2013 and 2014

	2013 (Jan - Sep)			2014 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.06)	($1.76)	18.9%	(0.08)	($2.07)	14.3%
$25 to $50	(0.04)	($2.41)	75.4%	(0.02)	($2.22)	69.2%
$50 to $75	0.00	($2.72)	4.6%	0.02	($2.00)	10.2%
$75 to $100	0.08	$7.07	0.4%	0.07	$4.31	1.5%
$100 to $125	0.00	$0.00	0.1%	0.14	$15.81	1.1%
$125 to $150	0.00	$0.00	0.0%	0.02	($2.02)	1.1%
>= $150	0.75	$118.80	0.0%	0.06	$12.12	2.5%

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.[49] These categories are designated Tier 1, Tier 2 and Tier 3.[50,51]

An AU, or associated unit, is a unit that is physically, electrically and economically identical to an FMU, but does not qualify for the same FMU adder based on the number of run-hours the unit is offer capped. For example, if a generating station had two identical units with identical electrical impacts on the system, one of 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.[52]

Table 3-29 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 nine months of 2014. Of the 104 units eligible in at least one month during the first nine months of 2014, 46 units (44.2 percent) were FMUs or AUs for all nine months, and 16 units (15.4 percent) qualified in only one month in the first nine months of 2014.

49 OA, Schedule 1 § 6.4.2.
50 114 FERC ¶ 61, 076 (2006).
51 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).
52 OA, Schedule 1 § 6.4.2. In 2007, the FERC approved OA revisions to clarify the AU criteria.

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Table 3-29 Frequently mitigated units and associated units total months eligible: 2013 and January through September, 2014

Months Adder-Eligible	2013	2014
1	10	16
2	22	7
3	14	0
4	10	3
5	5	4
6	8	17
7	7	1
8	3	10
9	1	46
10	2	
11	8	
12	22	
Total	112	104

Figure 3-22 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 June 30, 2014, there have been 351 unique units that have qualified for an FMU adder in at least one month. Of these 351 units, no unit qualified for an adder in all potential months. Two units qualified in 104 of the 105 possible months, and 93 of the 351 units (26.5 percent) have qualified for an adder in more than half of the possible months.

Figure 3-22 Frequently mitigated units and associated units total months eligible: February, 2006 through September, 2014

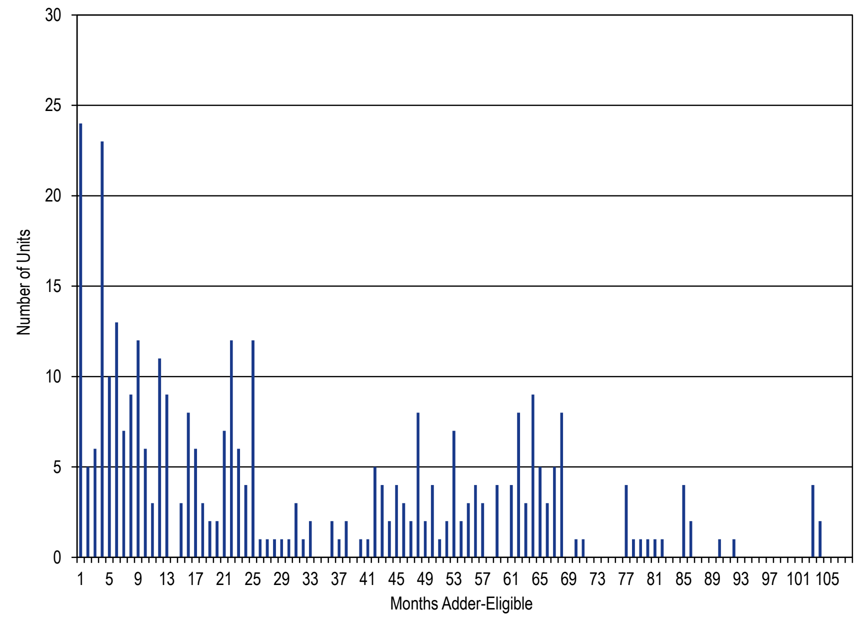


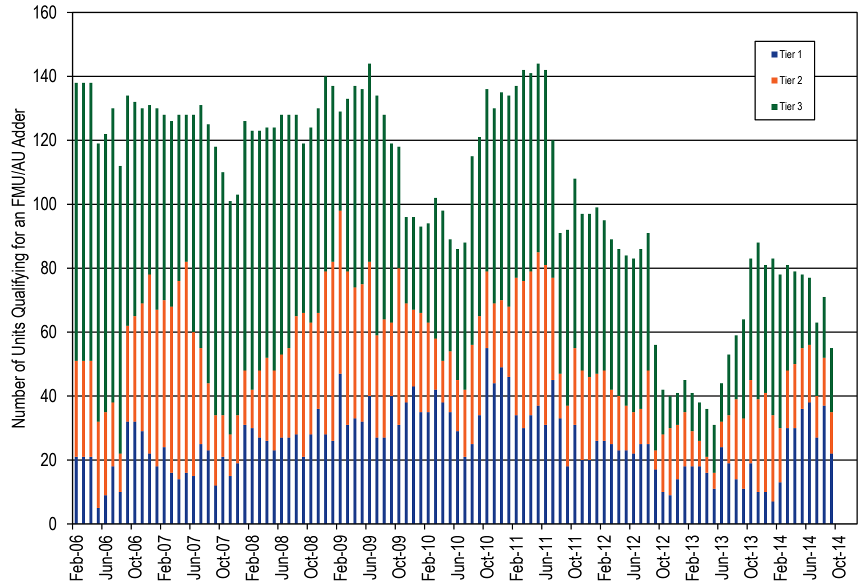
Table 3-30 shows, by month, the number of FMUs and AUs in 2013 and the first nine months of 2014. For example, in January 2014, there were 7 FMUs and AUs in Tier 1, 27 FMUs and AUs in Tier 2, and 49 FMUs and AUs in Tier 3.

Table 3-30 Number of frequently mitigated units and associated units (By month): 2013 and January through September, 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	30	20	29	79
May	11	5	15	31	36	19	23	78
June	24	8	12	44	38	18	21	77
July	19	15	19	53	27	13	23	63
August	14	25	20	59	37	15	19	71
September	11	22	31	64	22	13	20	55
October	19	26	38	83				
November	10	29	49	88				
December	10	31	40	81				

Figure 3-23 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 six months of 2013 and has continued to affect the number of FMU eligible units through the first nine months of 2014.

Figure 3-23 Frequently mitigated units and associated units (By month): February, 2006 through September, 2014



The PJM Tariff defines offer capped units as those capped to maintain system reliability as a result of limits on transmission capability.[53] 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

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

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designed to cover ACR for such units. The FMU adders were not designed for baseload units like those providing reactive service. If the FMU adders are not eliminated, adders must be specifically designed for such baseload units.

The FMU adder was filed with FERC in 2005, and approved effective February 2006.[54] 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 has recommended 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. The MMU and PJM proposed a compromise that maintained the ability of certain generating units to qualify for FMU adders but limiting FMU adders to units with net revenues less than unit going forward costs or ACR. At the June 26, 2014, meeting of the PJM Members Committee, the proposal received 65.6 percent of votes in favor of the joint MMU/PJM proposal, but failed to receive the 66.7 percent majority vote necessary to revise the PJM Operating Agreement. At the July 23, 2014, meeting of the PJM Board of Managers, the Board directed PJM staff to file the proposal, and on August 26, 2014, PJM submitted the joint MMU/PJM proposal to the Commission pursuant to section 206 of the Federal Power Act.[55] On October 31, 2014, the Commission conditionally approved the filing effective November 1, 2014.[56]

54 110 FERC ¶ 61,053 (2005).

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 3-31).

Table 3-31 Frequently mitigated units at risk of retirement: 2013

	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 that did not cover ACR in 2013 that are not scheduled to retire	6	1,434

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 437 buses, eligible for up-to congestion transaction bidding.[57] 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.

55 See *PJM Interconnection, L.L.C* Docket No. EL14-95-000 (August 26, 2014).
56 149 FERC ¶ 61,091 (2014).
57 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 3-24 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 nine months of 2014.

Figure 3-24 PJM day-ahead aggregate supply curves: 2014 example day

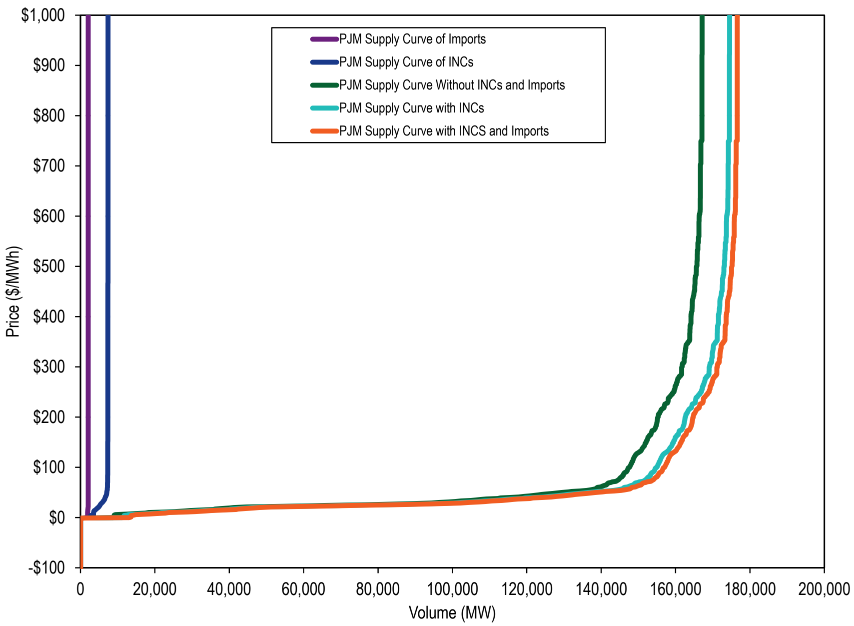

Table 3-32 shows the average hourly number of increment offers and decrement bids and the average hourly MW for 2013 and the first nine months of 2014. In the first nine months of 2014, the average hourly submitted and cleared increment offer MW decreased 26.4 and 36.4 percent, and the average hourly submitted and cleared decrement bid MW increased 0.9 and decreased 10.7 percent, compared to the first nine months of 2013.

Table 3-32 Hourly average number of cleared and submitted INCs, DECs by month: January 2013 through September 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	Apr	2,837	3,722	69	181	5,693	7,720	86	279
2014	May	3,981	6,008	73	248	6,042	10,238	104	418
2014	Jun	3,486	5,101	62	219	6,716	8,806	105	324
2014	Jul	3,892	6,350	66	305	7,331	9,514	146	402
2014	Aug	3,465	4,981	66	293	6,540	7,967	155	331
2014	Sep	3,416	5,020	69	356	6,996	8,839	198	417
2014	Annual	3,359	4,814	67	241	6,432	8,893	117	342

In the first nine months of 2014, up-to congestion transactions continued to displace increment offers and decrement bids, until September 8, 2014. While up-to congestion transactions (UTC) continued to displace increment offers and decrement bids, there was a sharp decrease in UTCs in September as a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[58] Table 3-33 shows the average hourly number of up-to congestion transactions and the average hourly MW for 2013 and the first nine months of 2014. In the first nine months of 2014, the average hourly up-to congestion submitted MW increased 19.4 percent and

58 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

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cleared MW increased 22.5 percent, compared to the first nine months of 2013.

Table 3-33 Hourly average of cleared and submitted up-to congestion bids by month: January 2013 through September 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	Apr	73,453	224,924	3,216	8,390
2014	May	73,853	251,463	3,057	8,860
2014	Jun	69,050	235,590	2,781	8,221
2014	Jul	66,800	212,485	2,855	7,856
2014	Aug	66,272	214,713	3,003	7,933
2014	Sep	25,370	86,237	1,210	2,979
2014	Annual	62,351	210,979	2,815	7,918

Table 3-34 shows the average hourly number of import and export transactions and the average hourly MW for 2013 and the first nine months of 2014. In the first nine months of 2014, the average hourly submitted and cleared import transaction MW decreased 2.7 and 0.8 percent, and the average hourly submitted and cleared export transaction MW increased 16.2 and 14.1 percent, compared to the first nine months of 2013.[59]

Table 3-34 Hourly average number of cleared and submitted import and export transactions by month: January 2013 through September 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	Apr	2,017	2,045	13	13	4,164	4,171	22	22
2014	May	2,162	2,168	13	13	2,664	2,674	18	18
2014	Jun	2,527	2,536	13	14	3,643	3,645	22	22
2014	Jul	2,236	2,279	12	12	3,786	3,787	21	21
2014	Aug	2,224	2,236	11	12	3,138	3,140	18	18
2014	Sep	2,114	2,123	11	11	3,744	3,755	23	23
2014	Annual	2,276	2,333	13	13	3,771	3,874	22	22

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

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Table 3-35 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 3-35 Type of day-ahead marginal units: January through September of 2014

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	2.9%	0.1%	94.4%	1.4%	1.1%	0.0%
Feb	2.0%	0.3%	94.7%	1.9%	1.1%	0.0%
Mar	2.6%	0.2%	94.7%	1.5%	1.0%	0.0%
Apr	2.3%	0.0%	95.1%	1.4%	1.2%	0.0%
May	1.6%	0.0%	92.0%	4.0%	2.4%	0.0%
Jun	2.0%	0.0%	94.6%	2.0%	1.4%	0.0%
Jul	2.1%	0.0%	93.9%	2.1%	1.9%	0.0%
Aug	2.2%	0.0%	94.7%	1.5%	1.6%	0.0%
Sep	7.2%	0.1%	83.9%	5.5%	3.4%	0.0%
Annual	2.5%	0.1%	93.7%	2.2%	1.6%	0.0%

Figure 3-25 shows the monthly volume of bid and cleared INC, DEC and up-to congestion bids by month for the period from January 2005 through September 2014. Figure 3-26 shows the daily volume of bid and cleared INC, DEC and up-to congestion bids for the period from January 2013 through September 2014 in order to show the drop off in UTC volumes compared to volumes in the last two years. Figure 3-27 shows the daily volume of bid and cleared INC, DEC and up-to congestion bids for the period from July 2014 through September 2014 in order to show the drop off in UTC volumes in more detail.

Figure 3-25 Monthly bid and cleared INCs, DECs, and UTCs (MW): January 2005 through September 2014

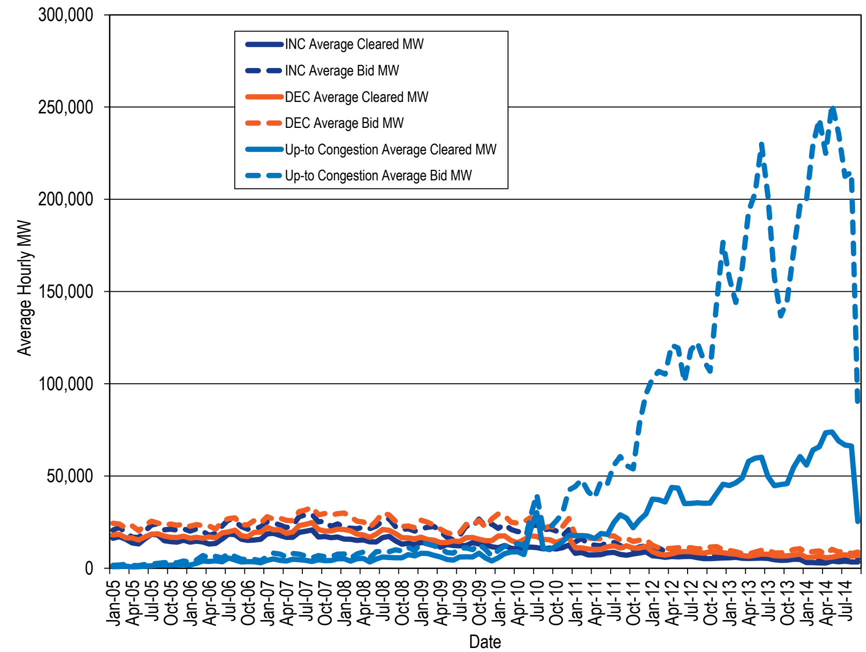

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Figure 3-26 Daily bid and cleared INCs, DECs, and UTCs (MW): January 2013 through September 2014

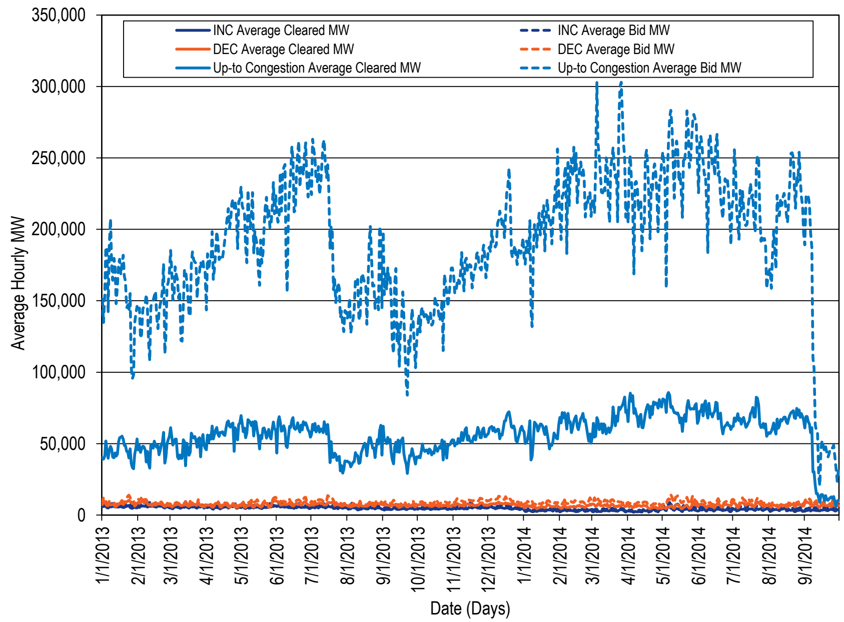
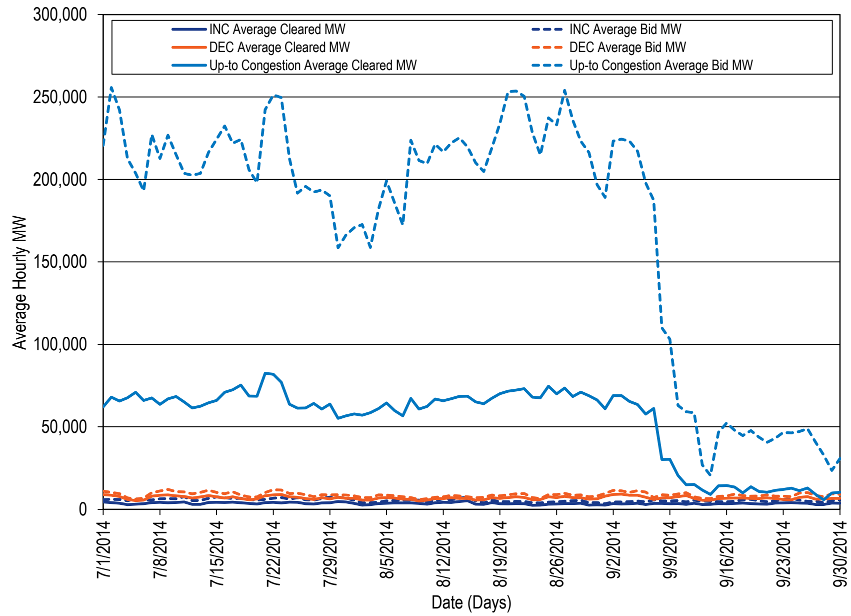


Figure 3-27 Daily bid and cleared INCs, DECs, and UTCs (MW): July 2014 through September 2014



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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 3-36 shows, for the first nine months of 2013 and the first nine months of 2014, the total increment offers and decrement bids by whether the parent organization is financial or physical. Table 3-37 shows, for the first nine months of 2013 and the first nine months of 2014, the total up-to congestion transactions by the type of parent organization. Table 3-38 shows, for the first nine months of 2013 and the first nine 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 63.9 percent of all the cleared up-to congestion MW in PJM in the first nine months of 2014, which is lower than the 65.1 percent in the first nine months of 2013. The cleared up-to congestion MW from financial companies increased 28.8 percent in the first nine months of 2014 compared to the first nine months of 2013. At the same time, the cleared up-to congestion MW from physical companies decreased by 31.7 percent decrease in the first nine months of 2014 compared to the first nine months for 2013.

Table 3-36 PJM INC and DEC bids by type of parent organization (MW): January through September of 2013 and 2014

	2013 (Jan - Sep)		2014 (Jan - Sep)	
Category	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	26,288,812	26.1%	34,951,487	38.9%
Physical	74,283,033	73.9%	54,842,824	61.1%
Total	100,571,845	100.0%	89,794,311	100.0%

Table 3-37 PJM up-to congestion transactions by type of parent organization (MW): January through September of 2013 and 2014

	2013 (Jan - Sep)		2014 (Jan - Sep)	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	308,437,367	94.9%	397,253,998	97.3%
Physical	16,406,890	5.1%	11,208,929	2.7%
Total	324,844,257	100.0%	408,462,927	100.0%

Table 3-38 PJM import and export transactions by type of parent organization (MW): January through September of 2013 and 2014

	2013 (Jan - Sep)		2014 (Jan - Sep)	
Category	Total Import and Export MW	Percentage	Total Import and Export MW	Percentage
Financial	15,685,768	42.8%	15,806,252	39.1%
Physical	20,998,911	57.2%	24,661,550	60.9%
Total	36,684,679	100.0%	40,467,801	100.0%

Table 3-39 shows increment offers and decrement bids bid by top ten locations for the first nine months of 2013 and the first nine months of 2014.

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Table 3-39 PJM virtual offers and bids by top ten locations (MW): January through September of 2013 and 2014

2013 (Jan - Sep)					2014 (Jan - Sep)				
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	18,260,786	20,364,245	38,625,031	WESTERN HUB	HUB	9,894,171	10,863,829	20,758,000
N ILLINOIS HUB	HUB	2,021,992	3,654,688	5,676,680	MISO	INTERFACE	343,925	5,474,143	5,818,068
SOUTHIMP	INTERFACE	5,631,492	0	5,631,492	PPL	ZONE	176,875	4,896,410	5,073,284
AEP-DAYTON HUB	HUB	2,617,334	2,689,122	5,306,456	SOUTHIMP	INTERFACE	4,663,488	0	4,663,488
IMO	INTERFACE	4,541,532	48,272	4,589,804	PECO	ZONE	216,231	4,185,850	4,402,081
PPL	ZONE	61,736	3,971,407	4,033,143	AEP-DAYTON HUB	HUB	1,802,758	1,888,119	3,690,877
MISO	INTERFACE	339,371	2,691,928	3,031,299	IMO	INTERFACE	3,198,562	172,008	3,370,570
PECO	ZONE	84,716	2,790,978	2,875,694	N ILLINOIS HUB	HUB	763,057	2,005,553	2,768,610
BGE	ZONE	26,503	1,524,108	1,550,611	BGE	ZONE	19,929	2,315,241	2,335,170
DOMINION HUB	HUB	241,575	1,292,010	1,533,584	MIAMIFOR22 KV MI7	GEN	0	1,096,814	1,096,814
Top ten total		33,827,037	39,026,758	72,853,795			21,078,997	32,897,966	53,976,963
PJM total		42,857,882	57,713,964	100,571,845			31,534,992	58,259,319	89,794,311
Top ten total as percent of PJM total		78.9%	67.6%	72.4%			66.8%	56.5%	60.1%

Table 3-40 shows up-to congestion transactions by import bids for the top ten locations for the first nine months of 2013 and the first nine months of 2014.[60]

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

2013 (Jan - Sep)				
Imports				
Source	Source Type	Sink	Sink Type	MW
OVEC	INTERFACE	DEOK	ZONE	939,254
OVEC	INTERFACE	STUART 1	AGGREGATE	882,562
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	805,645
NYIS	INTERFACE	HUDSON BC	AGGREGATE	762,162
NORTHWEST	INTERFACE	ZION 1	AGGREGATE	656,470
NORTHWEST	INTERFACE	BYRON 1	AGGREGATE	496,011
OVEC	INTERFACE	BECKJORD 6	AGGREGATE	455,771
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	452,895
OVEC	INTERFACE	SPORN 2	AGGREGATE	447,182
MISO	INTERFACE	112 WILTON	EHVAGG	399,528
Top ten total				6,297,480
PJM total				32,351,220
Top ten total as percent of PJM total				19.5%
2014 (Jan - Sep)				
Imports				
Source	Source Type	Sink	Sink Type	MW
HUDSONTP	INTERFACE	LEONIA 230 T-2	AGGREGATE	962,423
SOUTHEAST	INTERFACE	EDANVILL T1	AGGREGATE	759,991
MISO	INTERFACE	COOK	EHVAGG	620,933
OVEC	INTERFACE	BIG SANDY CT1	AGGREGATE	586,836
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	494,224
NEPTUNE	INTERFACE	SOUTHRIV 230	AGGREGATE	428,251
MISO	INTERFACE	AEP-DAYTON HUB	HUB	425,824
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	395,391
OVEC	INTERFACE	DEOK	ZONE	374,463
HUDSONTP	INTERFACE	LEONIA 230 T-1	AGGREGATE	373,872
Top ten total				5,422,207
PJM total				26,605,983
Top ten total as percent of PJM total				20.4%

Table 3-41 shows up-to congestion transactions by export bids for the top ten locations for the first nine months of 2013 and the first nine months of 2014.

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

2013 (Jan - Sep)				
Exports				
Source	Source Type	Sink	Sink Type	MW
JEFFERSON	EHVAGG	OVEC	INTERFACE	1,901,810
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	1,074,478
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	1,055,665
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	949,703
TANNERS CRK 4	AGGREGATE	OVEC	INTERFACE	875,503
GAVIN	EHVAGG	OVEC	INTERFACE	641,654
ROCKPORT	EHVAGG	OVEC	INTERFACE	571,378
EAST BEND 2	AGGREGATE	OVEC	INTERFACE	556,385
SPORN 3	AGGREGATE	OVEC	INTERFACE	545,195
F387 CHICAGOH	AGGREGATE	NIPSCO	INTERFACE	533,133
Top ten total				8,704,904
PJM total				38,431,224
Top ten total as percent of PJM total				22.7%
2014 (Jan - Sep)				
Exports				
Source	Source Type	Sink	Sink Type	MW
JEFFERSON	EHVAGG	OVEC	INTERFACE	2,072,977
TANNERS CRK 4	AGGREGATE	SOUTHWEST	INTERFACE	1,679,588
TANNERS CRK 4	AGGREGATE	OVEC	INTERFACE	809,023
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	663,858
ROCKPORT	EHVAGG	OVEC	INTERFACE	537,417
JEFFERSON	EHVAGG	SOUTHWEST	INTERFACE	530,747
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	508,396
BECKJORD 6	AGGREGATE	OVEC	INTERFACE	412,879
UNIV PARK 1-6	AGGREGATE	NIPSCO	INTERFACE	410,199
LINDEN A	AGGREGATE	LINDENVFT	INTERFACE	397,475
Top ten total				8,022,558
PJM total				28,341,400
Top ten total as percent of PJM total				28.3%

60 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.

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

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

2013 (Jan - Sep)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	685,232
NORTHWEST	INTERFACE	MISO	INTERFACE	396,607
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	300,204
IMO	INTERFACE	NYIS	INTERFACE	272,426
MISO	INTERFACE	NIPSCO	INTERFACE	259,584
OVEC	INTERFACE	IMO	INTERFACE	109,350
MISO	INTERFACE	SOUTHEXP	INTERFACE	104,052
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	88,280
MISO	INTERFACE	OVEC	INTERFACE	79,810
NORTHWEST	INTERFACE	OVEC	INTERFACE	78,419
Top ten total				2,373,962
PJM total				3,144,557
Top ten total as percent of PJM total				75.5%
2014 (Jan - Sep)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
NORTHWEST	INTERFACE	MISO	INTERFACE	757,930
OVEC	INTERFACE	SOUTHEXP	INTERFACE	325,649
MISO	INTERFACE	NORTHWEST	INTERFACE	281,282
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	255,598
MISO	INTERFACE	NIPSCO	INTERFACE	113,990
NYIS	INTERFACE	IMO	INTERFACE	96,966
MISO	INTERFACE	SOUTHEXP	INTERFACE	94,359
IMO	INTERFACE	NYIS	INTERFACE	89,338
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	84,922
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	71,509
Top ten total				2,171,543
PJM total				2,761,587
Top ten total as percent of PJM total				78.6%

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.[61] Up-to congestion transactions can now be made at internal buses. The top ten internal up-to congestion transaction locations were 10.2 percent of the PJM total internal up-to congestion transactions in the first nine months of 2014.

Table 3-43 shows up-to congestion transactions by internal bids for the top ten locations for the first nine months of 2013 and 2014.

Table 3-43 PJM cleared up-to congestion internal bids by top ten source and sink pairs (MW): January through September of 2013 and 2014

2013 (Jan - Sep)				
Internal				
Source	Source Type	Sink	Sink Type	MW
SUNBURY 1-3	AGGREGATE	CITIZENS	AGGREGATE	3,248,461
ATSI GEN HUB	HUB	ATSI	ZONE	3,180,687
MT STORM	EHVAGG	GREENLAND GAP	EHVAGG	3,060,670
FE GEN	AGGREGATE	ATSI	ZONE	1,778,421
AEP-DAYTON HUB	HUB	WESTERN HUB	HUB	1,690,443
CORDOVA	AGGREGATE	QUAD CITIES 2	AGGREGATE	1,519,249
WYOMING	EHVAGG	BROADFORD	EHVAGG	1,417,822
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	1,371,354
WHITPAIN	EHVAGG	ELROY	EHVAGG	1,313,998
NAPERVILLE	AGGREGATE	WINNETKA	AGGREGATE	1,189,073
Top ten total				19,770,178
PJM total				250,917,257
Top ten total as percent of PJM total				7.9%
2014 (Jan - Sep)				
Internal				
Source	Source Type	Sink	Sink Type	MW
MOUNTAINEER	EHVAGG	GAVIN	EHVAGG	6,614,543
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	5,207,634
MOUNTAINEER	EHVAGG	FLATLICK	EHVAGG	4,294,199
ATSI GEN HUB	HUB	ATSI	ZONE	3,921,656
VERNON BK 4	AGGREGATE	AEC - JC	AGGREGATE	3,733,527
FE GEN	AGGREGATE	ATSI	ZONE	3,324,975
DUMONT	EHVAGG	COOK	EHVAGG	2,370,640
JEFFERSON	EHVAGG	COOK	EHVAGG	2,291,396
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	2,035,779
TANNERS CRK 4	AGGREGATE	STUART DIESEL	AGGREGATE	1,810,214
Top ten total				35,604,562
PJM total				350,753,957
Top ten total as percent of PJM total				10.2%

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

Table 3-44 shows the number of source-sink pairs that were offered and cleared monthly in January of 2012 through the first nine months of 2014. The annual row in Table 3-44 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 nine 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 3-44 Number of PJM offered and cleared source and sink pairs: January 2012 through September 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	Apr	11,487	14,106	8,589	10,253
2014	May	11,215	13,477	7,734	9,532
2014	Jun	10,613	14,112	7,374	10,143
2014	Jul	10,057	12,304	7,202	8,486
2014	Aug	10,877	12,863	7,609	9,254
2014	Sep	5,618	11,269	4,281	8,743
2014	Annual	9,927	14,745	6,935	10,253

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Table 3-45 and Figure 3-28 show total cleared up-to congestion transactions by type for the first nine months of 2013 and the first nine months of 2014. Internal up-to congestion transactions in the first nine months of 2014 were 85.9 percent of all up-to congestion transactions for the first nine months of 2014.

Table 3-45 PJM cleared up-to congestion transactions by type (MW): January through September of 2013 and 2014

	2013 (Jan - Sep)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	6,297,480	8,704,904	2,373,962	19,770,178	20,482,915
PJM total (MW)	32,351,220	38,431,224	3,144,557	250,917,257	324,844,257
Top ten total as percent of PJM total	19.5%	22.7%	75.5%	7.9%	6.3%
PJM total as percent of all up-to congestion transactions	10.0%	11.8%	1.0%	77.2%	100.0%
	2014 (Jan - Sep)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	5,422,207	8,022,558	2,171,543	35,604,562	35,867,325
PJM total (MW)	26,605,983	28,341,400	2,761,587	350,753,957	408,462,927
Top ten total as percent of PJM total	20.4%	28.3%	78.6%	10.2%	8.8%
PJM total as percent of all up-to congestion transactions	6.5%	6.9%	0.7%	85.9%	100.0%

Figure 3-28 shows the initial increase and continued rise of internal up-to congestion transactions by month following the November 1, 2012 rule change permitting such transactions, until September 8, 2014. There was a sharp decrease in UTCs in September as a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[62] Figure 3-29 shows the daily cleared up-to congestion MW by transaction type for the period from January 2013 through September 2014 in order to show the drop off in UTC volumes compared to volumes in the last two years. Figure 3-30 shows the daily cleared up-to congestion MW by transaction type for the period from July 2014 through September 2014 in order to show the drop off in UTC volumes in more detail.

62 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

Figure 3-28 PJM cleared up-to congestion transactions by type (MW): January 2005 through September 2014

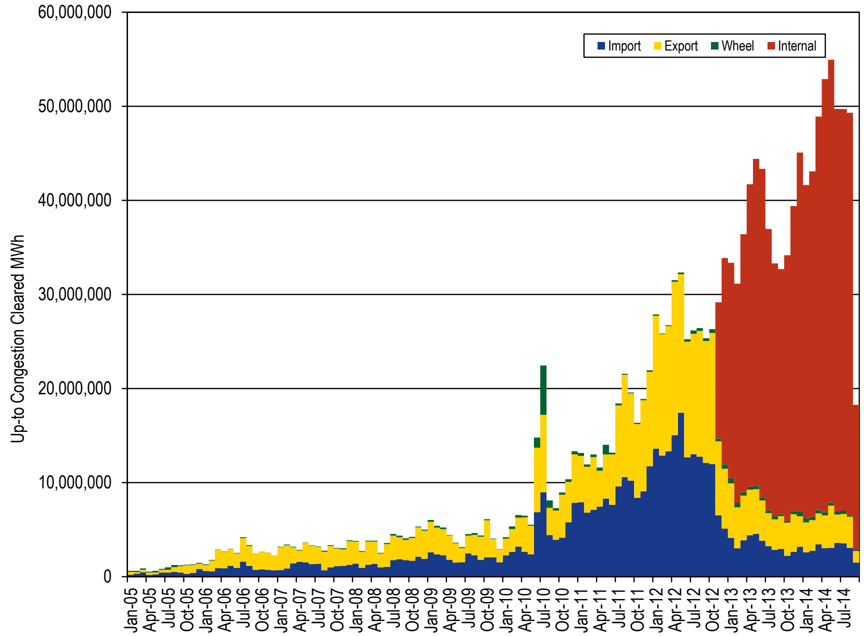

Figure 3-29 PJM daily cleared up-to congestion transaction by type (MW): January 2013 through September 2014

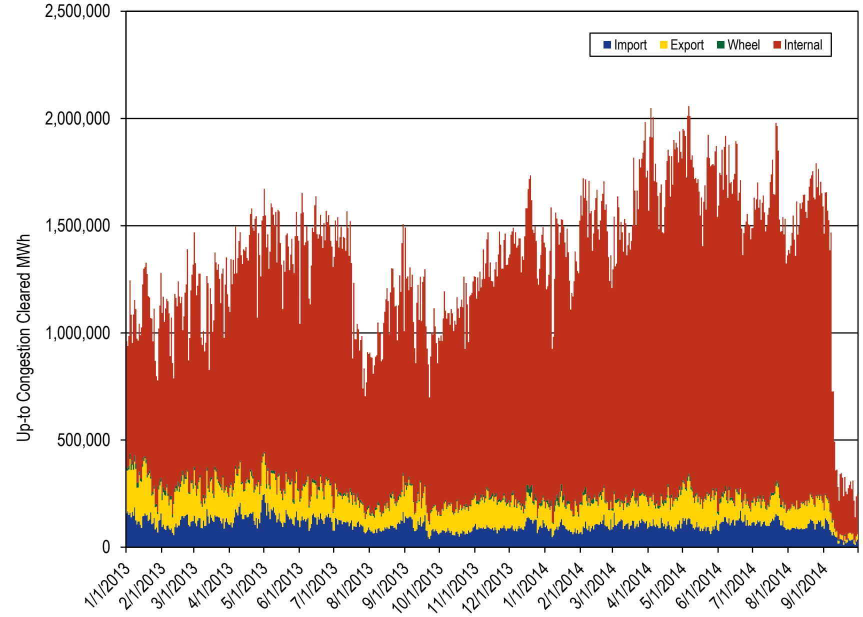

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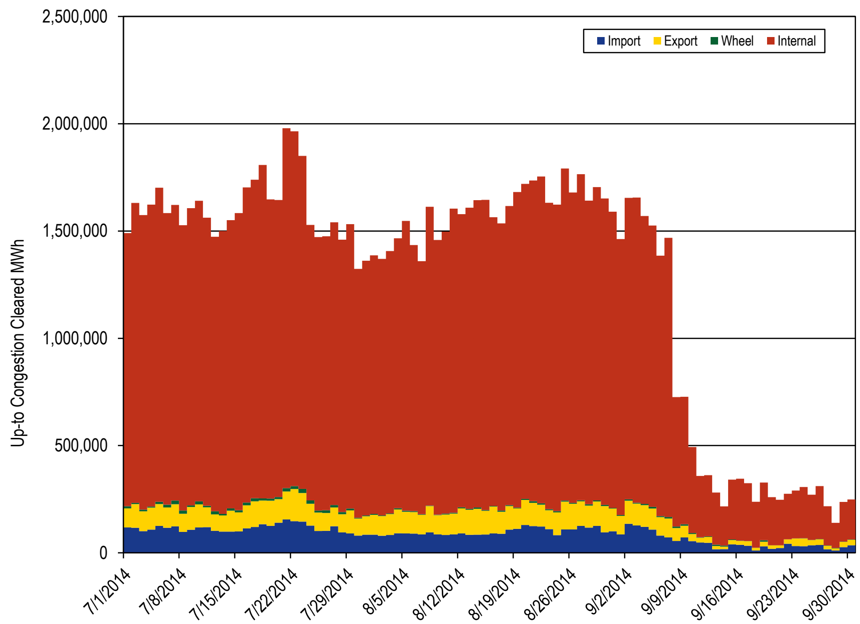
Figure 3-30 PJM daily cleared up-to congestion transaction by type (MW): July through September 2014



Generator Offers

Generator offers are categorized as dispatchable (Table 3-46) or self scheduled (Table 3-47).[63] 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 3-46 and Table 3-47 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 3-46 shows the proportion of MW offers by dispatchable units, by unit type and by offer price range, for the first nine months of 2014. For example, 66.4 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, 80.6 percent of all CC MW offers were dispatchable, including the 7.7 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, 41.4 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 nine months of 2014, 55.9 percent were offered as available for economic dispatch.

Table 3-46 Distribution of MW for dispatchable unit offer prices: January through September of 2014

	Dispatchable (Range)							
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	0.1%	66.4%	3.6%	1.6%	0.4%	0.8%	7.7%	80.6%
CT	0.1%	52.2%	26.1%	6.6%	1.9%	0.9%	11.4%	99.2%
Diesel	3.0%	14.4%	25.0%	8.9%	2.0%	1.7%	15.5%	70.4%
Run of River	0.0%	11.0%	0.0%	0.0%	0.0%	0.0%	0.0%	11.0%
Nuclear	8.6%	36.6%	0.0%	0.0%	0.0%	0.0%	11.9%	57.1%
Pumped Storage	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Solar	0.7%	6.7%	0.0%	0.0%	0.0%	0.0%	0.1%	7.5%
Steam	0.0%	45.7%	2.1%	0.3%	0.1%	0.2%	3.5%	51.9%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	40.1%	7.5%	0.0%	0.0%	0.0%	0.0%	0.6%	48.2%
All Dispatchable Offers	0.9%	41.4%	6.2%	1.6%	0.4%	0.4%	5.0%	55.9%

63 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 3-47 Distribution of MW for self scheduled offer prices: January through September 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	0.8%	0.3%	0.2%	16.4%	0.3%	0.1%	0.0%	0.0%	1.3%	19.4%
CT	0.4%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%
Diesel	25.7%	3.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	29.6%
Hydro	83.2%	5.4%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.1%	89.0%
Nuclear	21.1%	10.1%	2.8%	1.9%	0.0%	0.0%	0.0%	0.0%	6.9%	42.9%
Pumped Storage	60.7%	15.4%	5.0%	12.9%	0.0%	0.0%	0.0%	1.7%	4.1%	99.8%
Solar	67.9%	23.9%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	92.5%
Steam	4.6%	1.2%	0.2%	39.0%	0.1%	0.0%	0.0%	0.0%	2.8%	48.1%
Transaction	79.6%	20.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	5.6%	4.6%	33.6%	2.6%	0.0%	0.0%	0.0%	0.0%	5.4%	51.8%
All Self-Scheduled Offers	20.6%	2.2%	0.7%	18.7%	0.1%	0.0%	0.0%	0.0%	1.7%	44.1%

Table 3-47 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 nine months of 2014. For example, 16.4 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, 19.4 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 1.6 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 20.6 percent of all offers and self-scheduled and dispatchable units accounted for 19.6 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 nine months of 2014, 22.8 percent were offered as self scheduled and 21.3 percent were offered as self scheduled and dispatchable.

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.[64]

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

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

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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 3-48 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 3-48 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 3-27.

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.[65]

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 3-48 shows the mark-up component of the load-weighted LMP by fuel type and unit type using unadjusted and adjusted offers. The adjusted markup component of LMP increased from $0.85 in the first nine months of 2013 to $3.65 in the first nine months of 2014. The adjusted markup contribution of coal units in the first nine months of 2014 was $1.99. The adjusted mark-up component of all gas-fired units in the first nine months of 2014 was minus $1.05. Coal units accounted for 40 percent of the increased markup

65 See *PJM Manual 15: Cost Development Guidelines*, Revision: 25 (Effective July 28, 2014).

component of LMP in the first nine months of 2014 while gas units accounted for 37 percent. The markup component of wind units was 0.04. If a price-based offer is negative but less negative than a cost-based offer, the markup is positive. In the first nine months of 2014, among the wind units that were marginal, 1.74 percent had positive offer prices.

Table 3-48 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through September 2013 and 2014[66]

		2013 (Jan-Sep)		2014 (Jan-Sep)	
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	($0.65)	$0.86	$0.66	$1.99
Gas	CC	($0.01)	($0.01)	$0.72	$0.72
Gas	CT	$0.17	$0.17	$0.33	$0.33
Gas	Diesel	$0.06	$0.06	$0.03	$0.03
Gas	Steam	($0.35)	($0.35)	($0.03)	($0.03)
Municipal Waste	Steam	($0.01)	($0.01)	$0.20	$0.20
Oil	CC	$0.02	$0.02	$0.12	$0.12
Oil	CT	$0.02	$0.02	$0.12	$0.12
Oil	Diesel	$0.00	$0.00	$0.09	$0.09
Oil	Steam	$0.09	$0.10	$0.05	$0.05
Other	Steam	($0.02)	($0.02)	($0.00)	($0.00)
Uranium	Steam	($0.00)	($0.00)	$0.01	$0.01
Wind	Wind	$0.00	$0.00	$0.04	$0.04
Total		($0.67)	$0.85	$2.32	$3.65

Markup Component of Real-Time Price

Table 3-49 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on-peak and off-peak prices. Table 3-50 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on-peak and off-peak prices. In the first nine months of 2014, when using unadjusted cost offers, $2.32 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-offers, $3.65 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first nine months of 2014, the peak markup component was highest in March, $11.48 per MWh using unadjusted cost offers and $12.33 per MWh using adjusted cost offers. This corresponds to 15.13 percent and 16.25 percent of the real time load-weighted average LMP in March.

Table 3-49 Monthly markup components of real-time load-weighted LMP (Unadjusted): January through September 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	($3.10)	($3.87)	($2.38)	$5.84	$3.91	$7.69
Feb	($1.84)	($2.95)	($0.76)	$3.02	$0.88	$5.08
Mar	$0.67	($0.90)	$2.30	$7.27	$3.24	$11.48
Apr	($1.95)	($3.04)	($1.02)	($0.43)	($2.16)	$1.07
May	($1.16)	($2.92)	$0.32	$1.51	($1.27)	$4.18
Jun	($0.42)	($1.58)	$0.74	$2.22	($0.06)	$4.18
Jul	$3.86	($0.20)	$7.44	($0.01)	($0.88)	$0.74
Aug	($1.49)	($1.89)	($1.15)	($1.08)	($1.91)	($0.29)
Sep	($1.41)	($2.35)	($0.48)	$1.51	($0.13)	$3.01
Total	($0.66)	($2.13)	$0.70	$2.32	$0.35	$4.16

Table 3-50 Monthly markup components of real-time load-weighted LMP (Adjusted): January through September 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	($1.32)	($1.97)	($0.71)	$7.22	$5.48	$8.90
Feb	($0.05)	($1.04)	$0.91	$3.94	$1.97	$5.84
Mar	$2.28	$0.89	$3.71	$8.37	$4.59	$12.33
Apr	($0.69)	($1.39)	($0.10)	$0.86	($0.45)	$2.00
May	$0.22	($1.17)	$1.39	$2.66	$0.09	$5.12
Jun	$1.05	($0.04)	$2.14	$3.44	$1.45	$5.15
Jul	$5.22	$1.32	$8.65	$1.61	$0.69	$2.40
Aug	($0.06)	($0.36)	$0.19	$0.50	($0.29)	$1.25
Sep	$0.13	($0.58)	$0.83	$3.18	$1.65	$4.59
Total	$0.85	($0.42)	$2.04	$3.65	$1.85	$5.33

66 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 gas from municipal waste.

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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 nine months of 2014 and the first nine months of 2013 in Table 3-51 and for adjusted offers in Table 3-52. The smallest zonal all hours average markup component using unadjusted offers for the first nine months of 2014 was in the ComEd Zone, $1.40 per MWh, while the highest was in the Dominion Control Zone, $3.75 per MWh. The smallest zonal on peak average markup was in the ComEd Control Zone, $2.88 per MWh, while the highest was in the Dominion Control Zone, $5.98 per MWh.

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

	2013 (Jan - Sep)			2014 (Jan -Sep)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	($0.58)	($2.01)	$0.78	$2.19	$0.01	$4.23
AEP	($0.83)	($2.20)	$0.46	$1.93	($0.03)	$3.80
APS	($0.80)	($2.27)	$0.59	$2.15	$0.34	$3.87
ATSI	($0.66)	($2.16)	$0.72	$1.52	($0.20)	$3.13
BGE	($0.53)	($2.09)	$0.95	$3.64	$1.48	$5.66
ComEd	($0.76)	($2.20)	$0.53	$1.40	($0.19)	$2.88
DAY	($0.78)	($2.20)	$0.49	$1.65	($0.25)	$3.39
DEOK	($0.82)	($2.16)	$0.42	$1.62	($0.35)	$3.47
DLCO	($0.86)	($2.13)	$0.32	$1.66	$0.11	$3.11
DPL	($0.71)	($2.12)	$0.63	$3.37	$1.50	$5.11
Dominion	($0.42)	($2.11)	$1.19	$3.75	$1.37	$5.98
EKPC	$0.04	($1.74)	$1.71	$2.09	$0.24	$3.91
JCPL	($0.45)	($1.80)	$0.76	$1.88	($0.01)	$3.55
Met-Ed	($0.66)	($2.13)	$0.68	$1.99	$0.25	$3.58
PECO	($0.73)	($2.08)	$0.53	$2.28	$0.27	$4.14
PENELEC	($0.94)	($2.26)	$0.28	$2.48	$0.22	$4.56
PPL	($0.80)	($2.03)	$0.33	$2.61	$0.38	$4.66
PSEG	($0.34)	($1.97)	$1.15	$2.69	$0.47	$4.71
Pepco	($0.41)	($2.11)	$1.15	$3.42	$1.29	$5.36
RECO	$0.03	($1.78)	$1.56	$2.42	$0.61	$3.93

Table 3-52 Average real-time zonal markup component (Adjusted): January through September, 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
AECO	$0.90	($0.32)	$2.05	$3.42	$1.32	$5.39
AEP	$0.73	($0.46)	$1.86	$3.30	$1.56	$4.97
APS	$0.74	($0.53)	$1.95	$3.49	$1.84	$5.06
ATSI	$0.93	($0.41)	$2.17	$2.89	$1.36	$4.32
BGE	$1.02	($0.30)	$2.26	$5.22	$3.27	$7.03
ComEd	$0.73	($0.58)	$1.91	$2.75	$1.35	$4.05
DAY	$0.81	($0.43)	$1.93	$3.07	$1.37	$4.63
DEOK	$0.71	($0.46)	$1.80	$2.99	$1.21	$4.66
DLCO	$0.68	($0.44)	$1.73	$3.08	$1.70	$4.38
DPL	$0.80	($0.42)	$1.96	$4.55	$2.79	$6.19
Dominion	$1.07	($0.40)	$2.47	$5.12	$2.90	$7.19
EKPC	$1.52	($0.12)	$3.07	$3.45	$1.79	$5.08
JCPL	$0.85	($0.11)	$1.71	$3.06	$1.30	$4.60
Met-Ed	$0.80	($0.47)	$1.95	$3.15	$1.54	$4.61
PECO	$0.76	($0.43)	$1.87	$3.45	$1.56	$5.19
PENELEC	$0.63	($0.52)	$1.70	$3.76	$1.63	$5.73
PPL	$0.71	($0.35)	$1.68	$3.77	$1.67	$5.71
PSEG	$1.09	($0.28)	$2.35	$3.87	$1.75	$5.79
Pepco	$1.09	($0.36)	$2.41	$4.89	$2.95	$6.65
RECO	$1.43	($0.11)	$2.73	$3.68	$1.93	$5.14

Markup by Real Time Price Levels

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

	2013 (Jan - Sep)		2014 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($1.05)	73.5%	$2.17	74.2%
$25 to $50	($0.23)	22.1%	($0.42)	21.9%
$50 to $75	$0.05	2.9%	$0.32	2.8%
$75 to $100	$0.12	0.7%	$0.12	0.7%
$100 to $125	$0.11	0.3%	$0.09	0.3%
$125 to $150	$0.08	0.2%	$0.07	0.1%
>= $150	$0.25	0.3%	$0.01	0.0%

Table 3-54 Average real-time markup component (By price category, adjusted): January through September, 2013 and 2014

	2013 (Jan - Sep)		2014 (Jan -Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$0.05	73.5%	$3.05	74.2%
$25 to $50	$0.16	22.1%	($0.01)	21.9%
$50 to $75	$0.07	2.9%	$0.36	2.8%
$75 to $100	$0.14	0.7%	$0.13	0.7%
$100 to $125	$0.11	0.3%	$0.09	0.3%
$125 to $150	$0.07	0.2%	$0.07	0.1%
>= $150	$0.27	0.3%	$0.01	0.0%

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 3-55. INC, DEC and up-to congestion transactions have zero markups. Up-to congestion transactions were marginal for 93.6 percent of marginal resources in the first nine months of 2014. INCs were marginal for 1.6 percent of marginal resources and DECs were marginal for 2.2 percent of marginal resources in the first nine months of 2014. The percentage of marginal up-to congestion transactions decreased significantly beginning on September 8, 2014, as a result of the FERC's UTC uplift refund notice which became effective on September 8, 2014.[67] 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 3-55 shows the markup component of LMP for marginal generating resources. Generating resources were marginal in only 2.5 percent of marginal resources in the first nine months of 2014. The markup component of LMP for marginal generating resources increased in all categories but gas-fired steam units. The markup component of LMP for coal units increased from -$0.52 in the first nine months of 2013 to -$0.10 in the first nine months of 2014. The markup component of LMP for gas-fired CCs increased from -$0.49 in the first nine months of 2013 to -$0.24 in the first nine months of 2014.

Table 3-55 Markup component of the annual PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through September of 2013 and 2014

		2013 (Jan - Sep)		2014 (Jan - Sep)	
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	($0.52)	$0.13	($0.10)	$0.71
Gas	CC	($0.49)	($0.49)	($0.24)	($0.24)
Gas	CT	$0.00	$0.00	$0.03	$0.03
Gas	Diesel	$0.00	$0.00	$0.00	$0.00
Gas	Steam	$0.01	$0.01	($1.52)	($1.52)
Municipal Waste	Steam	$0.00	$0.00	($0.00)	($0.00)
Oil	CC	$0.00	$0.00	$0.01	$0.01
Oil	CT	$0.00	$0.00	$0.04	$0.05
Oil	Steam	$0.00	$0.00	$0.02	$0.02
Other	Steam	$0.00	$0.00	($0.02)	($0.01)
Total		($1.00)	($0.35)	($1.78)	($0.96)

67 See 18 CFR § 385.213 (2014).

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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 3-56 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted offers. Table 3-57 shows the markup component of average prices and of average monthly on-peak and off-peak prices using adjusted offers.

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

	2013 (Jan - Sep)			2014 (Jan - Sep)		
	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
Apr	($0.11)	($0.01)	($0.22)	($1.81)	($1.32)	($2.37)
May	($0.10)	($0.04)	($0.17)	($3.38)	($4.12)	($2.60)
Jun	($0.05)	$0.03	($0.14)	($3.06)	($4.43)	($1.45)
Jul	($0.08)	($0.01)	($0.15)	($3.19)	($3.92)	($2.33)
Aug	($0.06)	($0.01)	($0.11)	($4.27)	($4.33)	($4.19)
Sep	($0.27)	($0.13)	($0.42)	($1.55)	($1.47)	($1.64)
Annual	($1.00)	($0.66)	($1.37)	($1.75)	($1.72)	($1.78)

Table 3-57 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: January through September of 2013 and 2014

	2013 (Jan - Sep)			2014 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($2.03)	($2.33)	($1.72)	$1.44	$2.72	$0.09
Feb	($0.74)	$0.41	($1.93)	$1.40	$2.81	($0.08)
Mar	($0.26)	$1.29	($1.78)	$1.28	$0.52	$2.01
Apr	$0.07	$0.16	($0.03)	($0.38)	($0.34)	($0.42)
May	$0.02	$0.06	($0.02)	($2.14)	($3.32)	($0.90)
Jun	$0.07	$0.15	($0.02)	($1.72)	($3.44)	$0.29
Jul	($0.01)	$0.06	($0.08)	($2.96)	($3.65)	($2.16)
Aug	$0.01	$0.03	($0.01)	($4.09)	($4.13)	($4.05)
Sep	($0.12)	($0.02)	($0.22)	($1.37)	($1.20)	($1.55)
Annual	($0.35)	($0.05)	($0.67)	($0.93)	($1.10)	($0.74)

Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted offers is shown for each zone in Table 3-58. The markup component of annual average day-ahead price using adjusted offers is shown for each zone in Table 3-59. The markup component of the average day-ahead price increased in all zones from the first nine months of 2013 to the first nine months of 2014.

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

	2013 (Jan - Sep)			2014 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($1.00)	($0.71)	($1.30)	($2.27)	($2.65)	($1.85)
AEP	($1.01)	($0.62)	($1.42)	($1.53)	($1.29)	($1.78)
AP	($1.10)	($0.71)	($1.50)	($1.64)	($1.42)	($1.86)
ATSI	($1.01)	($0.63)	($1.42)	($1.65)	($1.42)	($1.89)
BGE	($1.00)	($0.71)	($1.33)	($1.78)	($1.84)	($1.72)
ComEd	($0.91)	($0.55)	($1.31)	($1.47)	($1.33)	($1.63)
DAY	($1.02)	($0.62)	($1.47)	($1.65)	($1.47)	($1.84)
DEOK	($0.96)	($0.56)	($1.39)	($1.70)	($1.63)	($1.78)
DLCO	($0.95)	($0.60)	($1.33)	($1.64)	($1.52)	($1.76)
DPL	($1.05)	($0.65)	($1.46)	($2.44)	($3.16)	($1.65)
Dominion	($0.98)	($0.67)	($1.32)	($1.91)	($1.93)	($1.88)
EKPC	($0.10)	($0.02)	($0.20)	($1.36)	($1.18)	($1.55)
JCPL	($1.18)	($1.05)	($1.34)	($2.17)	($2.43)	($1.87)
Met-Ed	($1.09)	($0.78)	($1.43)	($1.89)	($2.02)	($1.75)
PECO	($1.01)	($0.66)	($1.38)	($1.99)	($2.22)	($1.74)
PENELEC	($1.02)	($0.67)	($1.39)	($1.90)	($1.90)	($1.90)
PPL	($1.14)	($0.83)	($1.48)	($1.99)	($2.19)	($1.78)
PSEG	($0.96)	($0.64)	($1.33)	($2.06)	($2.25)	($1.84)
Pepco	($1.00)	($0.71)	($1.31)	($1.78)	($1.79)	($1.78)
RECO	($0.92)	($0.58)	($1.32)	($2.08)	($2.23)	($1.89)

Table 3-59 Day-ahead, average, zonal markup component (Adjusted): January through September of 2013 and 2014

	2013 (Jan - Sep)			2014 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.39)	($0.15)	($0.65)	($1.50)	($2.07)	($0.87)
AEP	($0.33)	$0.01	($0.69)	($0.68)	($0.67)	($0.70)
AP	($0.37)	($0.04)	($0.72)	($0.80)	($0.81)	($0.78)
ATSI	($0.34)	($0.01)	($0.71)	($0.79)	($0.78)	($0.81)
BGE	($0.32)	($0.07)	($0.58)	($0.92)	($1.19)	($0.62)
ComEd	($0.31)	$0.01	($0.67)	($0.64)	($0.70)	($0.57)
DAY	($0.35)	($0.00)	($0.75)	($0.79)	($0.83)	($0.74)
DEOK	($0.32)	$0.03	($0.70)	($0.88)	($1.02)	($0.73)
DLCO	($0.33)	($0.01)	($0.67)	($0.81)	($0.92)	($0.70)
DPL	($0.39)	($0.06)	($0.74)	($1.64)	($2.55)	($0.64)
Dominion	($0.33)	($0.07)	($0.61)	($1.10)	($1.33)	($0.84)
EKPC	($0.01)	$0.05	($0.08)	($0.53)	($0.58)	($0.49)
JCPL	($0.53)	($0.41)	($0.68)	($1.37)	($1.80)	($0.87)
Met-Ed	($0.44)	($0.18)	($0.72)	($1.08)	($1.41)	($0.73)
PECO	($0.38)	($0.08)	($0.69)	($1.21)	($1.63)	($0.75)
PENELEC	($0.31)	$0.01	($0.65)	($1.10)	($1.29)	($0.89)
PPL	($0.47)	($0.20)	($0.75)	($1.18)	($1.57)	($0.76)
PSEG	($0.36)	($0.09)	($0.67)	($1.31)	($1.66)	($0.91)
Pepco	($0.31)	($0.06)	($0.58)	($0.97)	($1.17)	($0.74)
RECO	($0.35)	($0.07)	($0.69)	($1.34)	($1.64)	($0.99)

Markup by Day-Ahead Price Levels

Table 3-60 and Table 3-61 show the average markup component of observed prices, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range. Table 3-60 shows that the average day-ahead markup increased significantly when day-ahead price is greater or equal to $150 from the first nine months of 2013 to the first nine months of 2014. There were 12 hours when generating resources were marginal in this category in the first nine months of 2013. However, there were 202 hours when generating resources were marginal in this category in the first nine months of 2014. The highest average markup was $437.10 in hour ending 1400 on January 28.

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

	2013 (Jan - Sep)		2014 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($1.89)	5.1%	($2.72)	9.2%
$25 to $50	($2.97)	83.9%	($2.53)	66.6%
$50 to $75	$0.75	8.9%	($3.70)	15.1%
$75 to $100	$0.03	1.2%	($1.93)	3.3%
$100 to $125	$0.01	0.4%	($6.78)	1.1%
$125 to $150	$0.00	0.1%	$3.31	0.9%
>= $150	($0.30)	0.4%	$10.26	3.8%

Table 3-61 Average, day-ahead markup (By LMP category, adjusted): January through June of 2013 and 2014

	2013 (Jan - Sep)		2014 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.71)	5.1%	($2.36)	9.2%
$25 to $50	($1.23)	83.9%	($1.28)	66.6%
$50 to $75	$1.31	8.9%	($2.69)	15.1%
$75 to $100	$0.13	1.2%	($1.58)	3.3%
$100 to $125	$0.03	0.4%	($6.44)	1.1%
$125 to $150	$0.01	0.1%	$3.74	0.9%
>= $150	($0.29)	0.4%	$11.15	3.8%

Prices

The conduct of individual market entities within a market structure is reflected in market prices.[68] 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 47.4 percent and 49.6 percent higher in the first nine months of 2014 than in the first nine months of 2013 as a result of higher fuel costs and higher demand.[69] Natural gas prices were higher, particularly in eastern zones, while coal prices were relatively constant. Natural gas prices in the first nine months of 2014 were higher than the first nine month of 2013, particularly in eastern zones.

PJM real-time energy market prices increased in the first nine months of 2014 compared to the first nine months of 2013. The average LMP was 41.3 percent higher in the first nine months of 2014 than in the first nine months of 2013, $57.72 per MWh versus $37.30 per MWh. The load-weighted average LMP was 47.4 percent higher in the first nine months of 2014 than in the first nine months of 2013, $58.60 per MWh versus $39.75 per MWh.

The fuel-cost adjusted, load-weighted, average LMP for the first nine months of 2014 was 13.6 percent lower than the load-weighted, average LMP for the first nine months of 2014. If fuel costs in the first nine months of 2014 had been the same as in the first nine months of 2013, holding everything else constant, the load-weighted LMP would have been lower, $50.62 per MWh instead of the observed $58.60 per MWh in the first nine months of 2014.

PJM day-ahead energy market prices increased in the first nine months of 2014 compared to the first nine months of 2013. The average LMP was 43.4 percent higher in the first nine months of 2014 than in the first nine months of 2013, $53.76 per MWh versus $37.50 per MWh. The load-weighted average LMP was 49.6 percent higher in the first nine months of 2014 than in the first nine months of 2013, $59.09 per MWh versus $39.49 per MWh.[70]

Real-Time LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[71]

68 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>.

69 There was an average increase of 1.6 heating degree days and average decrease of 0.3 cooling degree days in the first nine months of 2014 compared to the first nine months of 2013, which meant overall increased demand.

70 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."

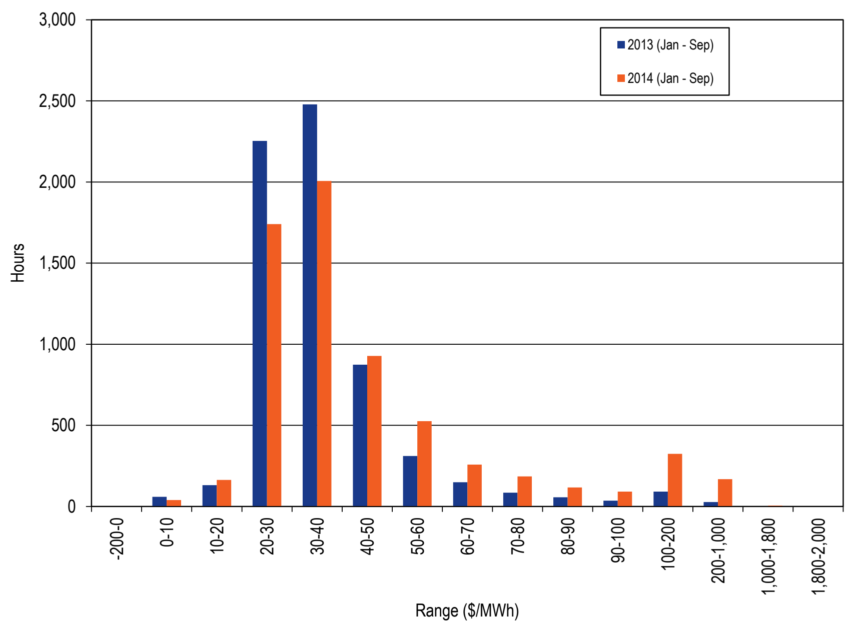
71 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price," for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 3-31 shows the hourly distribution of PJM real-time average LMP for the first nine months of 2013 and the first nine months of 2014. There was one hour in the first nine months of 2013 and 2014 in which the real-time LMP for the entire system was negative. Negative LMPs in the PJM Real-Time Market were primarily the result of marginal wind units with negative offer prices but may also result within a constrained area when inflexible generation exceeds the forecasted load. There were two hours in the first nine months of 2013 and eight hours in the first nine months of 2014 in which the PJM real-time LMP was $0.00. In 2014, there were six hours in January in which PJM real-time average LMP was greater than $1,000 and one hour that was greater $1,800.

Figure 3-31 Average LMP for the PJM Real-Time Energy Market: January through September of 2013 and 2014[72]



72 The data used in the version of this table in the *2014 Quarterly State of the Market Report for PJM: January through March* did not include LMP values greater than $1,000, but this table reflects those LMP values.

PJM Real-Time, Average LMP

Table 3-62 shows the PJM real-time, average LMP for the first nine months of each year of the 17-year period 1998 to 2014.[73]

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

	Real-Time LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$23.18	$16.86	$36.00	NA	NA	NA
1999	$31.65	$18.77	$83.28	36.6%	11.3%	131.3%
2000	$25.88	$18.22	$23.70	(18.2%)	(2.9%)	(71.5%)
2001	$36.00	$25.48	$51.30	39.1%	39.9%	116.4%
2002	$28.13	$20.70	$23.92	(21.9%)	(18.8%)	(53.4%)
2003	$40.42	$33.68	$26.00	43.7%	62.7%	8.7%
2004	$43.85	$39.99	$21.82	8.5%	18.7%	(16.1%)
2005	$54.69	$44.53	$33.67	24.7%	11.4%	54.3%
2006	$51.79	$43.50	$34.93	(5.3%)	(2.3%)	3.7%
2007	$57.34	$49.40	$35.52	10.7%	13.6%	1.7%
2008	$71.94	$61.33	$41.64	25.4%	24.2%	17.2%
2009	$37.42	$33.00	$17.92	(48.0%)	(46.2%)	(57.0%)
2010	$46.13	$37.89	$26.99	23.3%	14.8%	50.6%
2011	$45.79	$37.05	$32.25	(0.7%)	(2.2%)	19.5%
2012	$32.45	$28.78	$21.94	(29.1%)	(22.3%)	(32.0%)
2013	$37.30	$32.44	$22.84	15.0%	12.7%	4.1%
2014	$52.72	$36.06	$74.17	41.3%	11.2%	224.8%

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 3-63 shows the PJM real-time, load-weighted, average LMP for the first nine months of each year of the 17-year period 1998 to 2014.

73 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.

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Table 3-63 PJM real-time, load-weighted, average LMP (Dollars per MWh): January through September of 1998 through 2014

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$26.06	$18.20	$44.65	NA	NA	NA
1999	$38.65	$20.02	$104.17	48.3%	10.0%	133.3%
2000	$28.49	$19.30	$26.89	(26.3%)	(3.6%)	(74.2%)
2001	$40.96	$28.18	$64.57	43.8%	46.0%	140.1%
2002	$31.95	$23.09	$29.14	(22.0%)	(18.1%)	(54.9%)
2003	$43.57	$38.17	$26.53	36.3%	65.3%	(9.0%)
2004	$46.44	$43.03	$21.89	6.6%	12.7%	(17.5%)
2005	$60.44	$50.10	$36.52	30.2%	16.4%	66.9%
2006	$56.39	$46.82	$40.70	(6.7%)	(6.5%)	11.4%
2007	$61.83	$55.12	$37.98	9.7%	17.7%	(6.7%)
2008	$77.27	$66.73	$43.80	25.0%	21.1%	15.3%
2009	$39.57	$34.57	$19.04	(48.8%)	(48.2%)	(56.5%)
2010	$49.91	$40.33	$29.65	26.2%	16.7%	55.7%
2011	$49.48	$38.72	$37.02	(0.9%)	(4.0%)	24.8%
2012	$35.02	$29.84	$25.44	(29.2%)	(22.9%)	(31.3%)
2013	$39.75	$33.61	$26.47	13.5%	12.6%	4.0%
2014	$58.60	$37.93	$86.22	47.4%	12.8%	225.8%

Table 3-64 shows zonal real-time, and real-time, load-weighted, average LMP for the first nine months of 2013 and 2014. The real-time, load-weighted, average LMP increased by 47.4 percent compared to the first nine months of 2013.

Table 3-64 Zone real-time and real-time, load-weighted, average LMP (Dollars per MWh): January through September 2013 and 2014

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	(Jan-Sep) 2013 Average	(Jan-Sep) 2014 Average	Percentage Change	(Jan-Sep) 2013 Average	(Jan-Sep) 2014 Average	Percentage Change
AECO	$38.66	$57.16	47.8%	$42.09	$62.02	47.4%
AEP	$34.78	$47.07	35.3%	$36.31	$51.76	42.5%
AP	$36.58	$51.93	42.0%	$38.52	$58.66	52.3%
ATSI	$40.41	$48.95	21.1%	$44.63	$52.74	18.2%
BGE	$41.18	$65.16	58.2%	$44.55	$75.84	70.2%
ComEd	$32.02	$41.98	31.1%	$34.01	$44.79	31.7%
Day	$35.08	$46.82	33.5%	$36.91	$51.13	38.5%
DEOK	$33.42	$44.57	33.4%	$35.02	$48.45	38.4%
DLCO	$34.47	$44.05	27.8%	$36.44	$47.04	29.1%
Dominion	$38.97	$60.29	54.7%	$41.77	$70.61	69.1%
DPL	$39.93	$61.10	53.0%	$43.13	$72.28	67.6%
EKPC	$32.72	$44.65	36.4%	$35.06	$52.51	49.8%
JCPL	$39.89	$56.96	42.8%	$44.45	$62.59	40.8%
Met-Ed	$38.10	$55.42	45.5%	$40.70	$63.19	55.3%
PECO	$37.75	$56.16	48.8%	$40.44	$62.83	55.4%
PENELEC	$37.60	$52.20	38.8%	$39.51	$57.50	45.5%
Pepco	$40.49	$63.85	57.7%	$43.72	$73.53	68.2%
PPL	$37.87	$55.46	46.4%	$40.19	$64.58	60.7%
PSEG	$42.08	$59.98	42.5%	$45.47	$64.49	41.8%
RECO	$43.31	$58.85	35.9%	$47.74	$62.69	31.3%
PJM	$37.30	$52.72	41.3%	$39.75	$58.60	47.4%

Figure 3-32 and Figure 3-33 are contour maps of the real-time, load-weighted, average LMP for the first nine months of 2013 and 2014. Green represents the system marginal price (SMP) for January through September with each color to the right of green containing 5 percent of the pricing nodes above SMP and each color to the left of green containing 25 percent of pricing nodes below SMP. Prices in Eastern MAAC were all higher, on average, than the SMP for January through September of 2014.

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Figure 3-32 PJM real-time, load-weighted, average LMP: January through September 2013

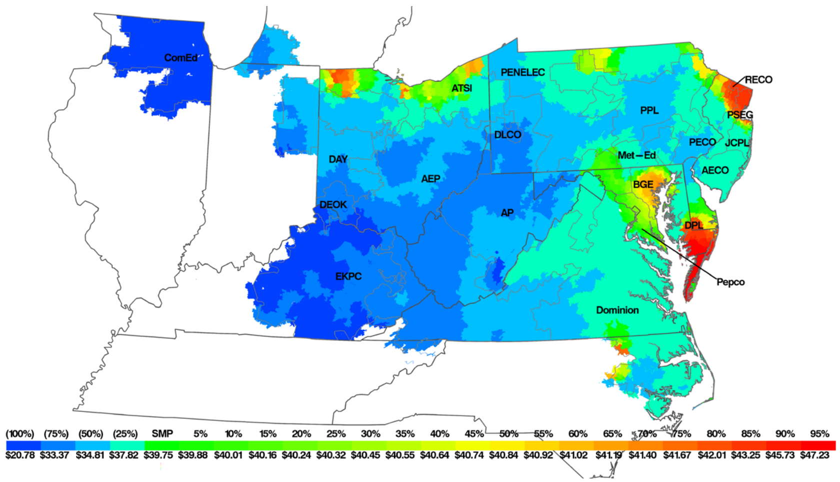

Figure 3-33 PJM real-time, load-weighted, average LMP: January through September 2014

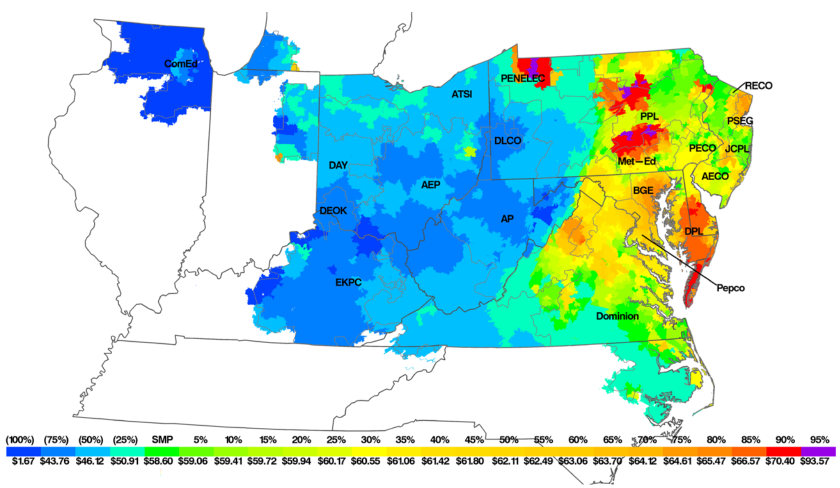

Table 3-65 shows zonal real-time, and real-time, load-weighted, average LMP for July through September of 2013 and 2014. The real-time, load-weighted, average LMP decreased by 15.4 percent compared to July through September of 2013.

Table 3-65 Zone real-time and real-time, load-weighted, average LMP (Dollars per MWh): July through September 2013 and 2014

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	(Jul-Sep) 2013 Average	(Jul-Sep) 2014 Average	Percentage Change	(Jul-Sep) 2013 Average	(Jul-Sep) 2014 Average	Percentage Change
AECO	$40.44	$34.30	(15.2%)	$46.27	$38.21	(17.4%)
AEP	$34.47	$33.11	(3.9%)	$36.98	$34.70	(6.2%)
AP	$37.27	$34.19	(8.3%)	$40.61	$36.16	(11.0%)
ATSI	$49.27	$34.24	(30.5%)	$58.99	$36.32	(38.4%)
BGE	$42.04	$40.38	(4.0%)	$47.22	$43.25	(8.4%)
ComEd	$33.05	$31.51	(4.7%)	$36.51	$33.33	(8.7%)
Day	$34.92	$33.92	(2.9%)	$38.03	$35.82	(5.8%)
DEOK	$33.20	$32.32	(2.6%)	$35.85	$34.10	(4.9%)
DLCO	$35.69	$31.93	(10.5%)	$39.27	$33.76	(14.0%)
Dominion	$39.89	$36.44	(8.7%)	$43.96	$38.87	(11.6%)
DPL	$42.70	$36.38	(14.8%)	$47.98	$41.12	(14.3%)
EKPC	$32.70	$32.20	(1.5%)	$35.18	$34.15	(2.9%)
JCPL	$42.37	$33.32	(21.4%)	$50.35	$37.42	(25.7%)
Met-Ed	$39.67	$32.29	(18.6%)	$44.19	$34.92	(21.0%)
PECO	$39.38	$33.01	(16.2%)	$44.03	$36.24	(17.7%)
PENELEC	$38.58	$34.35	(11.0%)	$41.97	$36.15	(13.9%)
Pepco	$41.24	$37.99	(7.9%)	$46.02	$40.63	(11.7%)
PPL	$39.47	$32.31	(18.1%)	$43.56	$34.72	(20.3%)
PSEG	$41.14	$33.58	(18.4%)	$46.65	$36.84	(21.0%)
RECO	$41.03	$33.28	(18.9%)	$48.22	$37.25	(22.7%)
PJM	$38.76	$34.20	(11.8%)	$43.01	$36.38	(15.4%)

Figure 3-34 and Figure 3-35 are contour maps of the real-time, load-weighted, average LMP for July through September of 2013 and for July through September of 2014. Green represents the system marginal price (SMP) for July through September with each color to the right of green containing 5 percent of the pricing nodes above SMP and each color to the left of green containing 25 percent of pricing nodes below SMP.

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Figure 3-34 PJM real-time, load-weighted, average LMP: July through September 2013

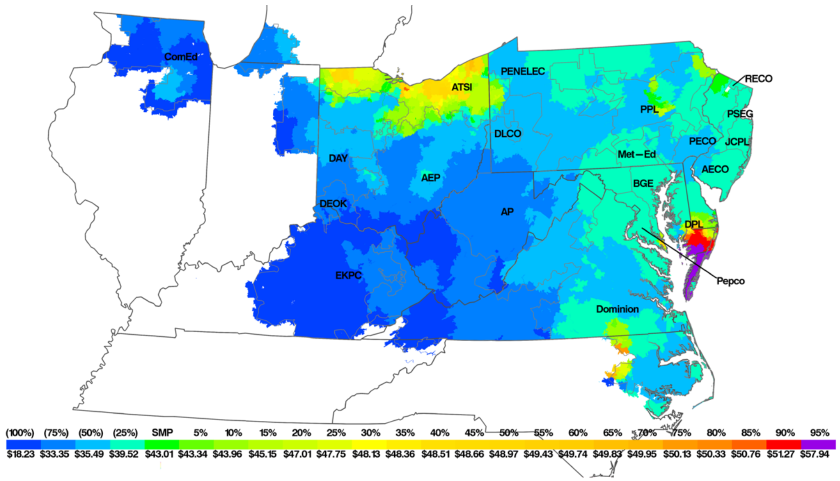
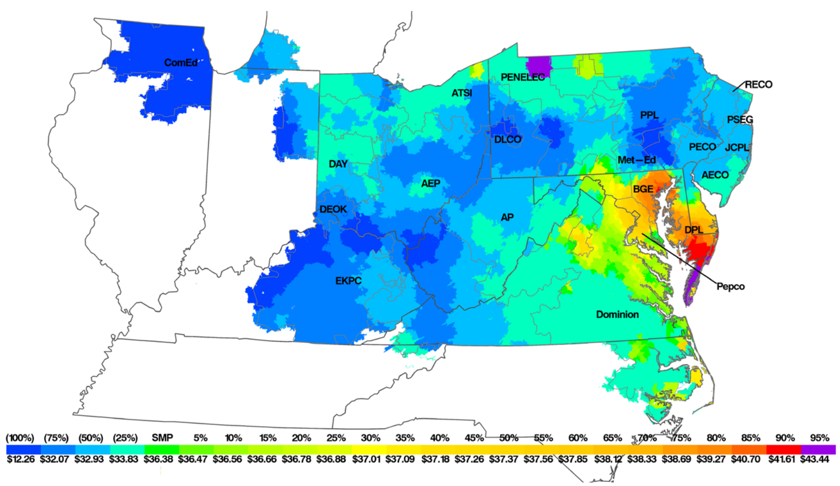


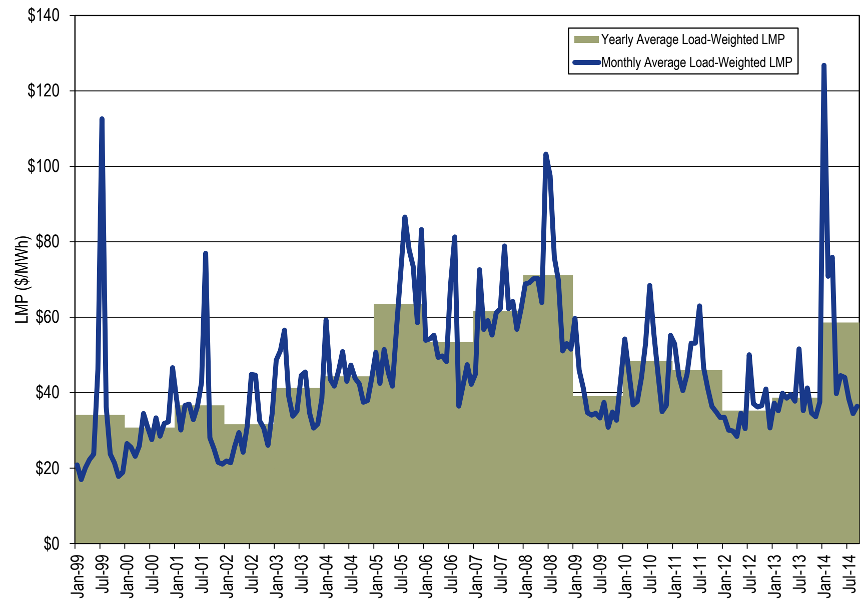
Figure 3-35 PJM real-time, load-weighted, average LMP: July through September 2014



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

Figure 3-36 shows the PJM real-time monthly and annual load-weighted LMP from 1999 through the first nine months of 2014.

Figure 3-36 PJM real-time, monthly and annual, load-weighted, average LMP: 1999 through September 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 nine months of 2014. Comparing fuel prices in the first nine months of 2014 to the first nine months of 2013,

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the price of Northern Appalachian coal was 0.5 percent higher; the price of Central Appalachian coal was 2.9 percent lower; the price of Powder River Basin coal was 10.1 percent higher; the price of eastern natural gas was 54.9 percent higher; and the price of western natural gas was 27.0 percent higher. Figure 3-37 shows monthly average spot fuel prices for the first nine months of 2013 and the first nine months of 2014.[74] Natural gas prices were above coal prices in the first nine months of 2014.

Figure 3-37 Spot average fuel price comparison with fuel delivery charges: 2012 through 2014 ($/MMBtu)

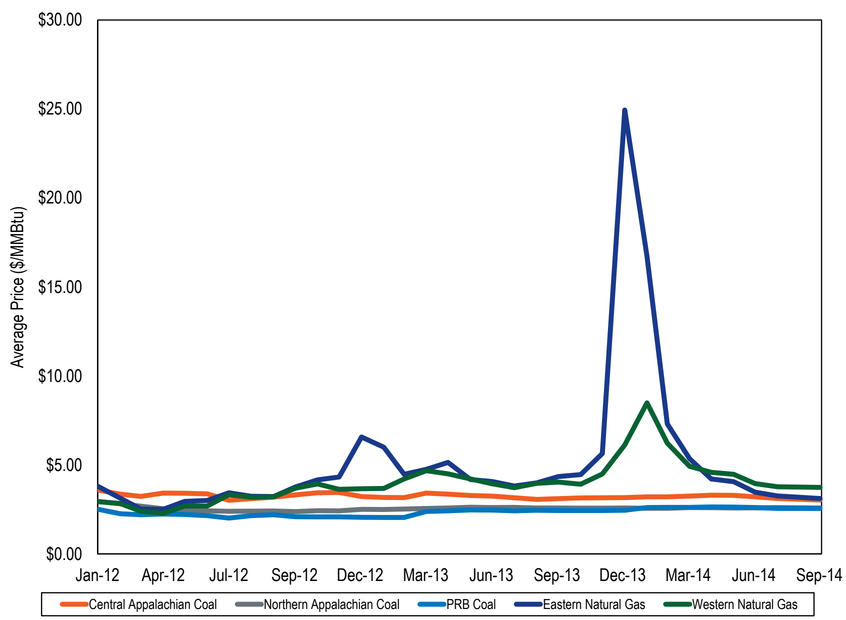

Table 3-66 compares the first nine months of 2014 PJM real time fuel-cost adjusted, load-weighted, average LMP to the first nine months of 2013 load-weighted, average LMP. The real time fuel-cost adjusted, load-weighted, average LMP for the first nine months of 2014 was 13.6 percent lower than the real time load-weighted, average LMP for the first nine months of 2014. The real-time, fuel-cost adjusted, load-weighted, average LMP for the first nine months of 2014 was 27.4 percent higher than the real time load-weighted LMP for the first nine months of 2013. If fuel costs in the first nine months of 2014 had been the same as in the first nine months of 2013, holding everything else constant, the real time load-weighted LMP in the first nine months of 2014 would have been lower, $50.62 per MWh instead of the observed $58.60 per MWh.

Table 3-66 PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): nine months over nine months

	2014 Load-Weighted LMP	2014 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$58.60	$50.62	(13.6%)
	2013 Load-Weighted LMP	2014 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$39.75	$50.62	27.4%
	2013 Load-Weighted LMP	2014 Load-Weighted LMP	Change
Average	$39.75	$58.60	47.4%

Table 3-67 shows the impact of each fuel type on the difference between the fuel-cost adjusted, load-weighted average LMP and the load-weighted LMP in the first nine months of 2014. Table 3-67 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 nine months of 2014.

74 Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily fuel price indices. Western natural gas prices are the average of Dominion North Point, Columbia Appalachia and Chicago Citygate daily fuel price indices. 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.

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Table 3-67 Change in PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh) by Fuel-type: nine months over nine months

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Coal	$0.12	1.5%
Gas	$7.89	98.8%
Oil	($0.03)	(0.3%)
Other	$0.00	0.0%
Uranium	$0.00	0.0%
Wind	($0.00)	(0.0%)
Total	$7.98	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 and Maryland.[75] 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 the commitment and dispatch of 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 reduced 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. In addition, in periods when generators providing energy cannot meet the reserve requirements, PJM can invoke shortage pricing. PJM invoked shortage pricing on January 6 and January 7 of 2014.[76] During the shortage conditions, the LMPs of marginal generators reflect the cost of not meeting the reserve requirements, the scarcity adder, which is defined by the operating reserve demand curve.

The components of LMP are shown in Table 3-68, including markup using unadjusted cost offers.[77] Table 3-68 shows that for the first nine months of 2014, 29.8 percent of the load-weighted LMP was the result of coal costs, 36.9 percent was the result of gas costs and 0.65 percent was the result of the cost of emission allowances. Markup was $2.32 per MWh. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP and does not reflect the other components of the offers of units burning that fuel. The component NA is the unexplainable portion of load-weighted LMP. Occasionally, PJM fails to provide all the data needed to accurately calculate generator sensitivity factors. As a result, the LMP for those intervals cannot be decomposed into component costs. The cumulative effect of excluding those five-minute intervals is the component NA. In the first nine months of 2014, nearly six 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 nine months of 2014 and the first nine months of 2013.

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

76 PJM triggered shortage pricing on January 6 following a RTO-wide voltage reduction action. PJM triggered shortage pricing on January 7, due to RTO-wide shortage of synchronized reserve.

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

Table 3-68 Components of PJM real-time (Unadjusted), annual, load-weighted, average LMP: January through September, 2013 and 2014

	2013 (Jan - Sep)		2014 (Jan - Sep)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Gas	$9.31	23.4%	$21.63	36.9%	13.5%
Coal	$15.42	38.8%	$17.46	29.8%	(9.0%)
Ten Percent Adder	$3.46	8.7%	$4.03	6.9%	(1.8%)
Oil	$0.67	1.7%	$3.64	6.2%	4.5%
VOM	$1.88	4.7%	$2.75	4.7%	(0.0%)
Emergency DR Adder	$0.11	0.3%	$2.40	4.1%	3.8%
Markup	($0.66)	(1.7%)	$2.32	4.0%	5.6%
NA	$1.33	3.4%	$1.94	3.3%	(0.0%)
Increase Generation Adder	$0.16	0.4%	$0.87	1.5%	1.1%
FMU Adder	$0.37	0.9%	$0.76	1.3%	0.4%
Ancillary Service Redispatch Cost	$0.21	0.5%	$0.54	0.9%	0.4%
CO2 Cost	$0.08	0.2%	$0.22	0.4%	0.2%
NOx Cost	$0.08	0.2%	$0.15	0.3%	0.1%
Scarcity Adder	$0.00	0.0%	$0.13	0.2%	0.2%
Other	($0.00)	(0.0%)	$0.03	0.1%	0.1%
Municipal Waste	$0.00	0.0%	$0.02	0.0%	0.0%
SO2 Cost	$0.01	0.0%	$0.01	0.0%	(0.0%)
Market-to-Market Adder	$0.01	0.0%	($0.01)	(0.0%)	(0.0%)
LPA-SCED Differential	($0.05)	(0.1%)	($0.01)	(0.0%)	0.1%
Wind	($0.00)	(0.0%)	($0.01)	(0.0%)	(0.0%)
Uranium	$0.00	0.0%	($0.01)	(0.0%)	(0.0%)
LPA Rounding Difference	$7.53	18.9%	($0.07)	(0.1%)	(19.1%)
Decrease Generation Adder	($0.16)	(0.4%)	($0.19)	(0.3%)	0.1%
Total	$39.75	100.0%	$58.60	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 3-68 and Table 3-72) markup is simply the difference between the price offer and the cost offer. In the second approach, (Table 3-69 and Table 3-73) the 10 percent markup is removed from the cost offers of coal units.

The components of LMP are shown in Table 3-69, including markup using adjusted cost offers.

Table 3-69 Components of PJM real-time (Adjusted), annual, load-weighted, average LMP: January through September, 2013 and 2014

	2013 (Jan - Sep)		2014 (Jan - Sep)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Gas	$9.31	23.4%	$21.63	36.9%	13.5%
Coal	$15.46	38.9%	$17.46	29.8%	(9.1%)
Markup	$0.85	2.1%	$3.65	6.2%	4.1%
Oil	$0.67	1.7%	$3.64	6.2%	4.5%
VOM	$1.89	4.7%	$2.75	4.7%	(0.1%)
Ten Percent Adder	$1.93	4.8%	$2.69	4.6%	(0.3%)
Emergency DR Adder	$0.11	0.3%	$2.40	4.1%	3.8%
NA	$1.33	3.4%	$1.94	3.3%	(0.0%)
Increase Generation Adder	$0.16	0.4%	$0.87	1.5%	1.1%
FMU Adder	$0.35	0.9%	$0.76	1.3%	0.4%
Ancillary Service Redispatch Cost	$0.21	0.5%	$0.54	0.9%	0.4%
CO2 Cost	$0.08	0.2%	$0.22	0.4%	0.2%
NOx Cost	$0.08	0.2%	$0.15	0.3%	0.1%
Scarcity Adder	$0.00	0.0%	$0.13	0.2%	0.2%
Other	($0.00)	(0.0%)	$0.03	0.1%	0.1%
Municipal Waste	$0.00	0.0%	$0.02	0.0%	0.0%
SO2 Cost	$0.01	0.0%	$0.01	0.0%	(0.0%)
Market-to-Market Adder	$0.01	0.0%	($0.01)	(0.0%)	(0.0%)
LPA-SCED Differential	($0.05)	(0.1%)	($0.01)	(0.0%)	0.1%
Wind	($0.00)	(0.0%)	($0.01)	(0.0%)	(0.0%)
Uranium	$0.00	0.0%	($0.01)	(0.0%)	(0.0%)
LPA Rounding Difference	$7.53	18.9%	($0.07)	(0.1%)	(19.0%)
Decrease Generation Adder	($0.16)	(0.4%)	($0.19)	(0.3%)	0.1%
Total	$39.75	100.0%	$58.60	100.0%	0.0%

Day-Ahead LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[78]

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-38 shows the hourly distribution of PJM day-ahead average LMP for the first nine months of 2013 and the first nine months of 2014.

78 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>.

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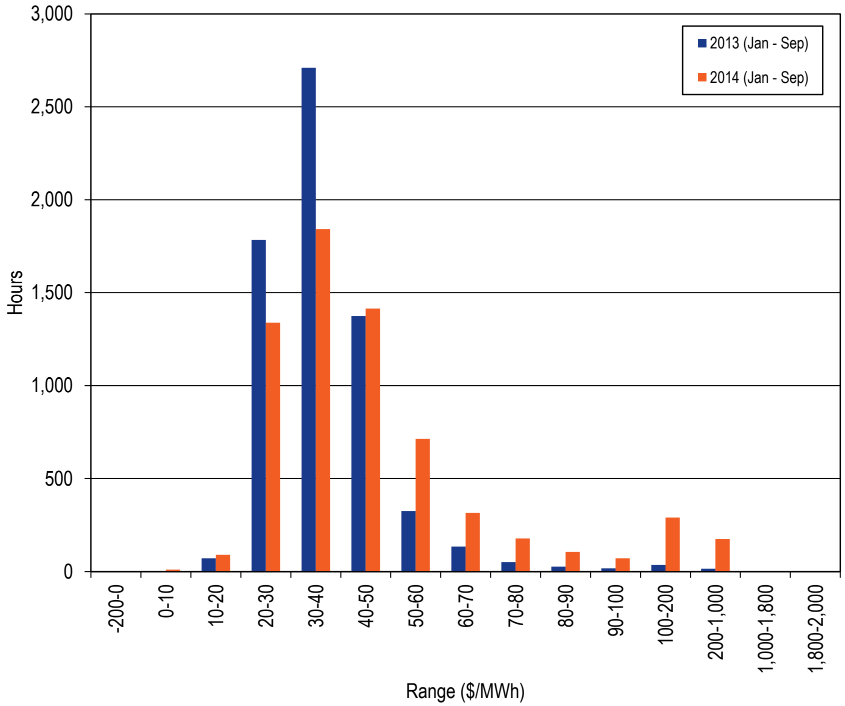
Figure 3-38 Average LMP for the PJM Day-Ahead Energy Market: January through September of 2013 and 2014



PJM Day-Ahead, Average LMP

Table 3-70 shows the PJM day-ahead, average LMP for the first nine months of each year of the 14-year period 2001 to 2014.

Table 3-70 PJM day-ahead, average LMP (Dollars per MWh): January through September of 2001 through 2014

	Day-Ahead LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.07	$30.02	$34.25	NA	NA	NA
2002	$28.29	$22.54	$19.09	(21.6%)	(24.9%)	(44.3%)
2003	$41.20	$38.24	$22.02	45.6%	69.7%	15.4%
2004	$42.64	$42.07	$17.47	3.5%	10.0%	(20.7%)
2005	$54.48	$46.67	$28.83	27.8%	10.9%	65.1%
2006	$50.45	$46.32	$24.93	(7.4%)	(0.8%)	(13.5%)
2007	$54.24	$51.40	$24.95	7.5%	11.0%	0.1%
2008	$71.43	$66.38	$33.11	31.7%	29.2%	32.7%
2009	$37.35	$35.29	$14.32	(47.7%)	(46.8%)	(56.8%)
2010	$45.81	$41.03	$19.59	22.7%	16.3%	36.8%
2011	$45.14	$40.20	$22.68	(1.5%)	(2.0%)	15.7%
2012	$32.16	$30.10	$14.54	(28.8%)	(25.1%)	(35.9%)
2013	$37.50	$34.70	$16.96	16.6%	15.3%	16.6%
2014	$53.76	$39.92	$58.98	43.4%	15.0%	247.8%

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.

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PJM Day-Ahead, Load-Weighted, Average LMP

Table 3-71 shows the PJM day-ahead, load-weighted, average LMP for the first nine months of each year of the 14-year period 2001 to 2014.

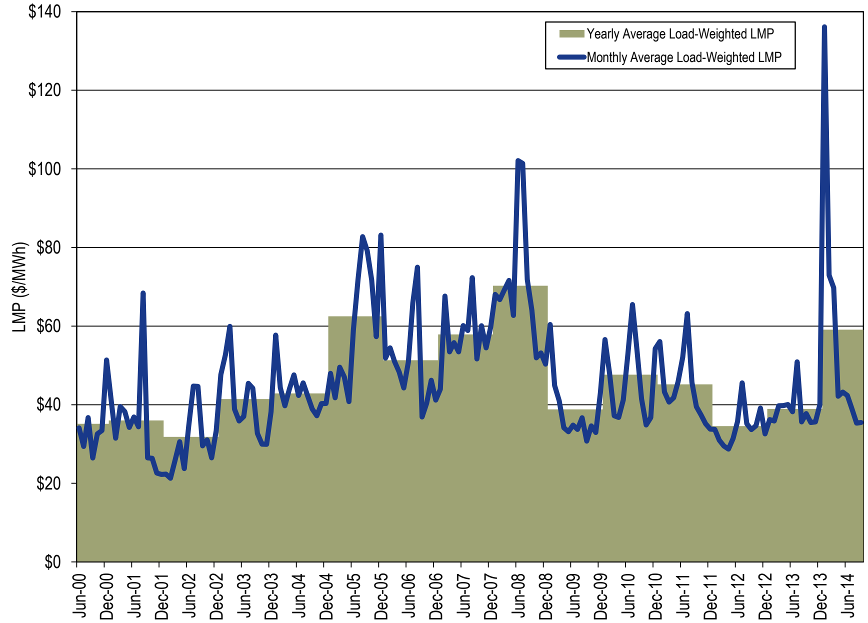
Table 3-71 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through September of 2001 through 2014

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$39.88	$32.68	$42.01	NA	NA	NA
2002	$32.29	$25.22	$22.81	(19.0%)	(22.8%)	(45.7%)
2003	$44.11	$41.51	$22.34	36.6%	64.6%	(2.1%)
2004	$44.59	$44.47	$17.40	1.1%	7.1%	(22.1%)
2005	$59.51	$51.33	$31.13	33.5%	15.4%	78.9%
2006	$54.19	$48.87	$28.35	(8.9%)	(4.8%)	(8.9%)
2007	$57.79	$55.62	$26.07	6.6%	13.8%	(8.0%)
2008	$75.96	$70.35	$35.19	31.5%	26.5%	35.0%
2009	$39.35	$36.92	$14.98	(48.2%)	(47.5%)	(57.4%)
2010	$49.12	$43.33	$21.35	24.8%	17.4%	42.6%
2011	$48.34	$42.35	$26.54	(1.6%)	(2.3%)	24.3%
2012	$34.29	$31.17	$17.12	(29.1%)	(26.4%)	(35.5%)
2013	$39.49	$35.96	$19.90	15.1%	15.4%	16.3%
2014	$59.09	$42.08	$67.27	49.6%	17.0%	238.0%

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

Figure 3-39 shows the PJM day-ahead, monthly and annual, load-weighted LMP from 2000 through the first nine months of 2014.[79]

Figure 3-39 Day-ahead, monthly and annual, load-weighted, average LMP: 2000 through September 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 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.

79 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.

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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.[80] 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 3-72, including markup using unadjusted cost offers. Table 3-72 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In the first nine months of 2014, 23.3 percent of the load-weighted LMP was the result of gas, 13.6 percent was the result of the up-to congestion transactions and 15.8 percent was the result of DEC bids.

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

Table 3-72 Components of PJM day-ahead, (unadjusted) annual, load-weighted, average LMP (Dollars per MWh): January through September of 2013 and 2014[81]

	2013 (Jan - Sep)		2014 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$2.83	7.2%	$13.77	23.3%	16.2%
Coal	$5.94	15.0%	$10.93	18.5%	3.5%
DEC	$2.31	5.8%	$9.33	15.8%	9.9%
INC	$1.50	3.8%	$8.75	14.8%	11.0%
Up-to Congestion Transaction	$25.87	65.5%	$8.01	13.6%	(52.0%)
Dispatchable Transaction	$0.17	0.4%	$2.84	4.8%	4.4%
Ten Percent Cost Adder	$0.94	2.4%	$2.78	4.7%	2.3%
VOM	$0.63	1.6%	$1.56	2.6%	1.1%
Price Sensitive Demand	$0.06	0.2%	$1.09	1.8%	1.7%
Oil	$0.00	0.0%	$1.05	1.8%	1.8%
FMU Adder	$0.02	0.1%	$0.41	0.7%	0.6%
Import	$0.00	0.0%	$0.16	0.3%	0.3%
CO2	$0.02	0.0%	$0.13	0.2%	0.2%
Other	$0.00	0.0%	$0.10	0.2%	0.2%
NOx	$0.02	0.1%	$0.10	0.2%	0.1%
DASR Offer Adder	$0.00	0.0%	$0.06	0.1%	0.1%
SO2	$0.00	0.0%	$0.01	0.0%	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%	0.0%
Municipal Waste	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.00)	(0.0%)	($0.01)	(0.0%)	(0.0%)
DASR LOC Adder	$0.02	0.0%	($0.04)	(0.1%)	(0.1%)
Markup	($1.00)	(2.5%)	($1.75)	(3.0%)	(0.4%)
NA	$0.15	0.4%	($0.19)	(0.3%)	(0.7%)
Total	$39.49	100.0%	$59.09	100.0%	0.0%

81 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 3-73 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.

Table 3-73 Components of PJM day-ahead, (adjusted) annual, load-weighted, average LMP (Dollars per MWh): January through September of 2013 and 2014

	2013 (Jan - Sep)		2014 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$2.83	7.2%	$13.77	23.3%	16.2%
Coal	$5.94	15.0%	$10.90	18.4%	3.4%
DEC	$2.31	5.8%	$9.33	15.8%	9.9%
INC	$1.50	3.8%	$8.75	14.8%	11.0%
Up-to Congestion Transaction	$25.87	65.5%	$8.01	13.6%	(52.0%)
Dispatchable Transaction	$0.17	0.4%	$2.84	4.8%	4.4%
Ten Percent Cost Adder	$0.29	0.7%	$1.99	3.4%	2.6%
VOM	$0.63	1.6%	$1.56	2.6%	1.0%
Price Sensitive Demand	$0.06	0.2%	$1.09	1.8%	1.7%
Oil	$0.00	0.0%	$1.05	1.8%	1.8%
FMU Adder	$0.02	0.1%	$0.41	0.7%	0.6%
Import	$0.00	0.0%	$0.16	0.3%	0.3%
CO2	$0.02	0.0%	$0.13	0.2%	0.2%
Other	$0.00	0.0%	$0.10	0.2%	0.2%
NOx	$0.02	0.1%	$0.10	0.2%	0.1%
DASR Offer Adder	$0.00	0.0%	$0.06	0.1%	0.1%
SO2	$0.00	0.0%	$0.01	0.0%	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%	0.0%
Municipal Waste	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.00)	(0.0%)	($0.01)	(0.0%)	(0.0%)
DASR LOC Adder	$0.02	0.0%	($0.04)	(0.1%)	(0.1%)
Markup	($0.35)	(0.9%)	($0.93)	(1.6%)	(0.7%)
NA	$0.15	0.4%	($0.19)	(0.3%)	(0.7%)
Total	$39.49	100.0%	$59.09	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

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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 3-74 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 nine months of 2013 and the first nine months of 2014. In the first nine months of 2014, 55.3 percent of all cleared UTC transactions were net profitable, with 67.5 percent of the source side profitable and 33.6 percent of the sink side profitable (Table 3-74).

Table 3-74 Cleared UTC profitability by source and sink point: January through September of 2013 and 2014[82]

(Jan-Sep)	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	Profitable UTC	Profitable Source	Profitable Sink
2013	10,309,092	5,637,485	6,663,751	3,734,928	54.7%	64.6%	36.2%
2014	18,442,292	10,204,493	12,449,206	6,195,177	55.3%	67.5%	33.6%

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.

82 Calculations exclude PJM administrative charges.

Substantial virtual trading activity does not guarantee that market power cannot be exercised in the Day-Ahead Energy Market. Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis (Figure 3-41).

Table 3-75 shows that the difference between the average real-time price and the average day-ahead price was -$0.20 per MWh in the first nine months of 2013 and -$1.04 per MWh in the first nine months of 2014. The difference between average peak real-time price and the average peak day-ahead price was $0.16 per MWh in the first nine months of 2013 and -$1.72 per MWh in the first nine months of 2014.

Table 3-75 Day-ahead and real-time average LMP (Dollars per MWh): January through September of 2013 and 2014[83]

	2013 (Jan - Sep)				2014 (Jan - Sep)			
	Day Ahead	Real Time	Difference	Percent of Real Time	Day Ahead	Real Time	Difference	Percent of Real Time
Average	$37.50	$37.30	($0.20)	(0.5%)	$53.76	$52.72	($1.04)	(2.0%)
Median	$34.70	$32.44	($2.26)	(7.0%)	$39.92	$36.06	($3.86)	(10.7%)
Standard deviation	$16.96	$22.84	$5.88	25.7%	$58.98	$74.17	$15.18	20.5%
Peak average	$44.58	$44.74	$0.16	0.4%	$67.11	$65.39	($1.72)	(2.6%)
Peak median	$40.32	$37.41	($2.91)	(7.8%)	$47.70	$42.97	($4.73)	(11.0%)
Peak standard deviation	$21.37	$28.77	$7.40	25.7%	$73.24	$93.17	$19.94	21.4%
Off peak average	$31.31	$30.80	($0.51)	(1.7%)	$42.09	$41.64	($0.45)	(1.1%)
Off peak median	$30.07	$28.44	($1.63)	(5.7%)	$32.85	$30.34	($2.52)	(8.3%)
Off peak standard deviation	$7.58	$12.77	$5.19	40.7%	$39.24	$49.58	$10.34	20.9%

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 3-76 shows the difference between the Real-Time and the Day-Ahead Energy Market prices for the first nine months of each year of the 14-year period 2001 to 2014.

Table 3-76 Day-ahead and real-time average LMP (Dollars per MWh): January through September of 2001 through 2014

(Jan-Sep)	Day Ahead	Real Time	Difference	Percent of Real Time
2001	$36.07	$36.00	($0.07)	(0.2%)
2002	$28.29	$28.13	($0.16)	(0.6%)
2003	$41.20	$40.42	($0.77)	(1.9%)
2004	$42.64	$43.85	$1.22	2.9%
2005	$54.48	$54.69	$0.21	0.4%
2006	$50.45	$51.79	$1.34	2.7%
2007	$54.24	$57.34	$3.10	5.7%
2008	$71.43	$71.94	$0.51	0.7%
2009	$37.35	$37.42	$0.08	0.2%
2010	$45.81	$46.13	$0.32	0.7%
2011	$45.14	$45.79	$0.65	1.4%
2012	$32.16	$32.45	$0.29	0.9%
2013	$37.50	$37.30	($0.20)	(0.5%)
2014	$53.76	$52.72	($1.04)	(1.9%)

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

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Table 3-77 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for the first nine months of 2007 through 2014.

Table 3-77 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): January through September 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	0.03%
($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	0.08%
($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	0.09%
($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	0.18%
($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	0.26%
($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	0.34%
($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	0.43%
($250) to ($200)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%	1	0.02%	14	0.64%
($200) to ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%	4	0.08%	3	0.06%	14	0.85%
($150) to ($100)	0	0.00%	1	0.02%	0	0.00%	0	0.00%	2	0.05%	6	0.17%	5	0.14%	45	1.54%
($100) to ($50)	26	0.40%	88	1.35%	3	0.05%	13	0.20%	49	0.79%	17	0.43%	9	0.27%	89	2.90%
($50) to $0	3,385	52.07%	3,730	58.08%	3,776	57.69%	4,091	62.65%	4,011	62.02%	4,112	62.97%	4,338	66.49%	4,301	68.55%
$0 to $50	2,914	96.55%	2,448	95.32%	2,736	99.45%	2,288	97.57%	2,290	96.98%	2,343	98.60%	2,112	98.73%	1,871	97.11%
$50 to $100	193	99.50%	264	99.33%	34	99.97%	130	99.56%	169	99.56%	61	99.53%	58	99.62%	97	98.60%
$100 to $150	21	99.82%	37	99.89%	2	100.00%	20	99.86%	21	99.88%	14	99.74%	12	99.80%	37	99.16%
$150 to $200	4	99.88%	4	99.95%	0	100.00%	8	99.98%	2	99.91%	10	99.89%	10	99.95%	18	99.44%
$200 to $250	1	99.89%	2	99.98%	0	100.00%	1	100.00%	3	99.95%	4	99.95%	1	99.97%	9	99.57%
$250 to $300	3	99.94%	0	99.98%	0	100.00%	0	100.00%	0	99.95%	1	99.97%	2	100.00%	8	99.69%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.95%	2	100.00%	0	100.00%	3	99.74%
$350 to $400	0	99.97%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%	0	100.00%	3	99.79%
$400 to $450	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%	0	100.00%	2	99.82%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%	0	100.00%	0	99.82%
$500 to $750	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%	0	100.00%	7	99.92%
$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	99.92%
$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	99.94%
>= $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%

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Figure 3-40 shows the hourly differences between day-ahead and real-time hourly LMP in the first nine months of 2014.

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

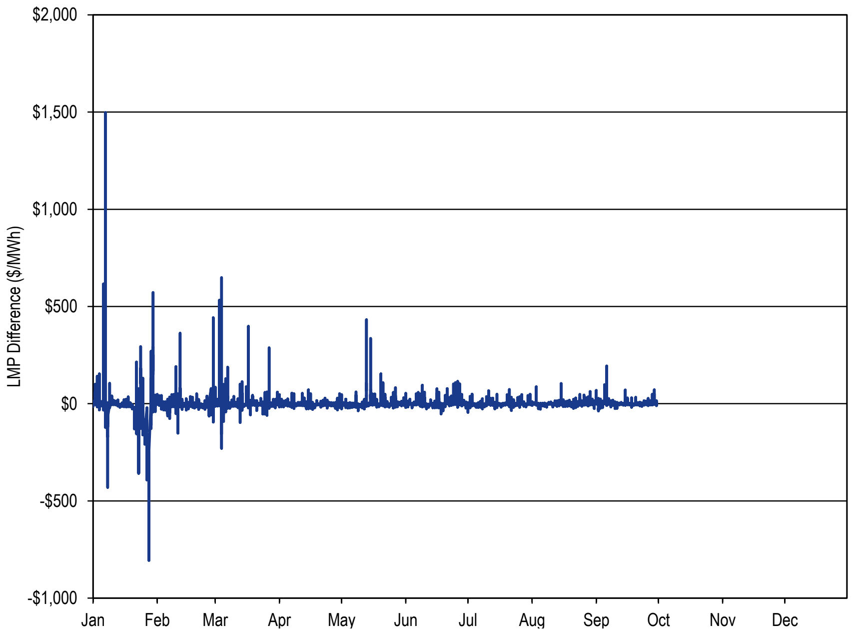

Figure 3-41 shows the monthly average differences between the day-ahead and real-time LMP in the first nine months of 2014.

Figure 3-41 Monthly average of real-time minus day-ahead LMP: January through September of 2014

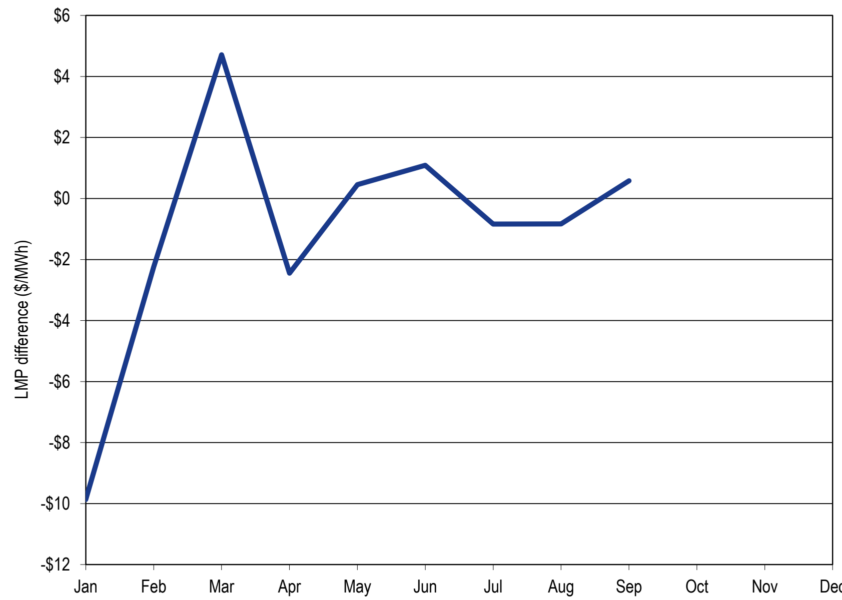

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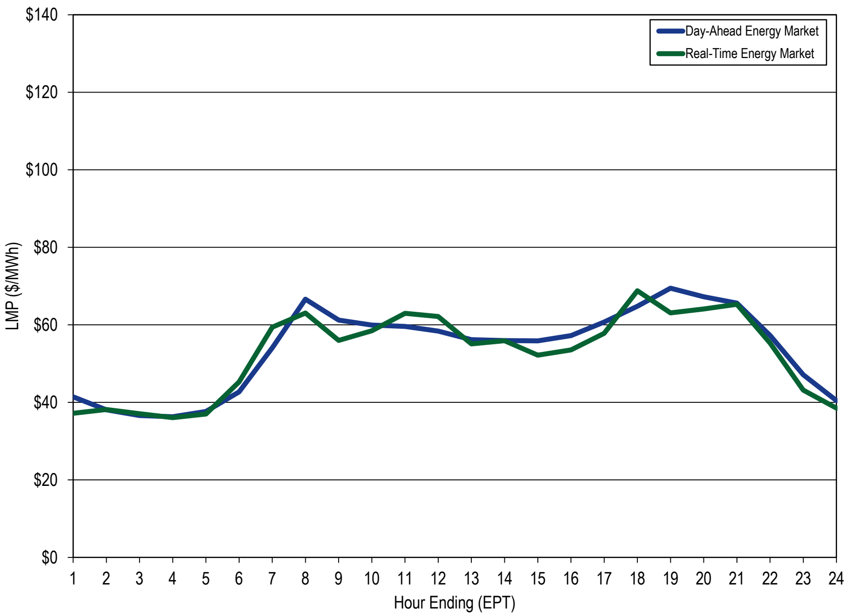
Figure 3-42 shows day-ahead and real-time LMP on an average hourly basis for the first nine months of 2014.

Figure 3-42 PJM system hourly average LMP: January through September 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 3-78 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in the first nine months of 2013 and 2014.

Table 3-78 Summary of emergency events declared January through September, 2013 and 2014

	Number of days events declared	
Event Type	Jan - Sep, 2013	Jan - Sep, 2014
Cold Weather Alert	4	25
Hot Weather Alert	17	7
Maximum Emergency Generation Alert	4	6
Primary Reserve Alert	0	2
Voltage Reduction Alert	0	2
Primary Reserve Warning	0	1
Voltage Reduction Warning	1	4
Emergency Load Management Long Lead Time	5	6
Emergency Load Management Short Lead Time	1	6
Maximum Emergency Action	5	8
Emergency Energy Bids Requested	0	3
Voltage Reduction Action	0	1
Shortage Pricing	0	2
Energy export recalls from PJM capacity resources	0	0

Emergency procedures

PJM declares alerts at least a day prior to the operating day to warn members of possible emergency actions that could be taken during the operating day. In real time on the operating day, PJM issues warnings notifying members of system conditions that could result in emergency actions during the operating day.

PJM declared cold weather alerts on 25 days in the first nine months of 2014 compared to only four days in the first nine months of 2013.[84] 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 hot weather alerts on seven days in the first nine months of 2014 compared to 17 days in the first nine months of 2013.[85] The purpose of a hot weather alert is to prepare personnel and facilities for expected extreme hot and humid weather conditions, generally when temperatures are forecast to exceed 90 degrees Fahrenheit with high humidity.

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

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PJM declared maximum emergency generation alerts on six days in the first nine months of 2014 compared to four days in the first nine months of 2013. All the maximum emergency generation alerts in 2014 were associated with cold weather conditions in the period from January through March. In 2013, the maximum emergency generation alerts were associated with hot weather conditions in the period from July through September. 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.[86] This means that if PJM directs members to load maximum emergency generation during the operating day, the resources must be able to increase generation above the maximum economic level of their offer.

PJM declared a primary reserve alert on two days in the first nine 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 nine 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 nine 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 nine months of 2014 compared to one day in the first nine months of 2013. 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 nine months of 2014 compared to five days in the first nine months of 2013 (short lead time load reductions were declared on only one of the five days). 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 nine 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 nine months of 2014 compared to five days in the first nine months of 2013. 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 nine 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 nine months of 2014. On January 7, PJM requested bids for emergency

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

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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 nine months of 2014.

PJM issued a voltage reduction action on one day (January 6) in the first nine 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 29 spinning events in the first nine months of 2014 compared to 15 in the first nine months of 2013.[87] Of the 29, 19 were classified as system disturbances (caused by unit trips or line trip).

Table 3-79 provides a description of PJM declared emergency procedures.

Table 3-79 Description of Emergency Procedures

Emergency Procedure	Purpose
Cold Weather Alert	To prepare personnel and facilities for extreme cold weather conditions, generally when forecast weather conditions approach minimum or temperatures fall below ten degrees Fahrenheit.
Hot Weather Alert	To prepare personnel and facilities for extreme hot and/or humid weather conditions, generally when forecast temperatures exceed 90 degrees with high humidity.
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.

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

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Table 3-80 shows the dates on which emergency alerts and warnings were declared as well as emergency actions were implemented in the first nine months of 2014.

Table 3-80 PJM declared emergency alerts, warnings and actions: January through September, 2014

Dates	Cold Weather Alert	Hot 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										
6/17/2014		PJM									
6/18/2014		PJM									
6/19/2014		Dominion									
7/1/2014		PJM Mid-Atlantic and Southern regions									
7/2/2014		PJM Mid-Atlantic and Southern regions									
7/8/2014		PJM Mid-Atlantic and Southern regions									
9/2/2014		PJM Mid-Atlantic and Southern regions									

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