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 2014, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM Energy Market results were competitive in 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 in 2014 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1153 with a minimum of 930 and a maximum of 1468 in 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, although high markups during periods of high demand did affect prices.
- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes. 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 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 basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive

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 *2014 State of the Market Report for PJM*, Appendix A, "PJM Geography."

2 PJM. OATT Attachment M (PJM Market Monitoring Plan).

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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. If market-based offer caps are raised, aggregate market power mitigation rules need to be developed.

Overview

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. Average offered real-time generation decreased by 4,715 MW, or 2.7 percent, from 176,316 MW in summer 2013 to 171,602 MW in summer 2014.[4] In 2014, 2,659 MW of new capacity were added to PJM. This new generation was more than offset by the deactivation of 29 units (2,949.3 MW).

  PJM average real-time generation in 2014 increased by 0.2 percent from 89,769 MW in 2013 to 89,966 MW. The PJM average real-time generation in 2014 would have increased by 1.4 percent from 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 2014, including INCs, up-to congestion transactions, and imports, decreased by 6.9 percent from 2013, from 150,595 MW to 140,239 MW. PJM average day-ahead supply in 2014, including INCs, up-to congestion transactions, and imports, would have decreased by 7.3 percent from 2013, from 150,595 MW to 139,607 MW, if the EKPC Transmission Zone had not been included in the comparison.

- **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 2014, coal units provided 43.5 percent, nuclear units 34.3 percent and gas units 17.3 percent of total generation. Compared to 2013, generation from coal units decreased 1.3 percent, generation from gas units increased 7.6 percent and generation from nuclear units increased 0.1 percent.

- **Marginal Resources.** In the PJM Real-Time Energy Market, in 2014, coal units were 52.9 percent of marginal resources and natural gas units were 35.8 percent of marginal resources. In 2013, coal units were 56.94 percent and natural gas units were 34.72 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market in 2014, up-to congestion transactions were 91.0 percent of marginal resources, INCs were 2.3 percent of marginal resources, DECs were 3.3 percent of marginal resources, and generation resources were 3.4 percent of marginal resources in 2014. From September 8, 2014 to December 31, 2014, up-to congestion transaction were 67.3 percent of marginal resources, INCs were 8.3 percent of marginal resources, DECs were 12.7 percent of marginal resources, and generation resources were 11.6 percent of marginal resources.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM system peak load during 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 2013, which was 157,508 MW in the HE 1700 on July 18, 2013.

  The PJM system peak load during the first three months of 2014 was 140,467 MW in HE 1900 on January 7, 2014, which was 13,835 MW, or 10.9 percent, higher than the PJM peak for the first three months of 2013 of 126,632 MW in HE 19 on January 22, 2013.

  PJM average real-time load in 2014 increased by 0.9 percent from 2013, from 88,332 MW to 89,099 MW. The PJM average real-time load in 2014 would have increased by 0.1 percent from 2013, from 87,537

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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MW to 87,637 MW, if the EKPC Transmission Zone had not been included.

PJM average day-ahead demand in 2014, including DECs, up-to congestion transactions, and exports, decreased by 1.4 percent from 2013, from 148,132 MW to 146,120 MW. The PJM average day-ahead demand in 2014, including DECs, up-to congestion transactions, and exports, would have decreased 1.9 percent from 2013, from 148,132 MW to 145,282 MW, if the EKPC Transmission Zone had not been included in the comparison.

- **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 2014, 10.6 percent of real-time load was supplied by bilateral contracts, 26.7 percent by spot market purchases and 62.7 percent by self-supply. Compared with 2013, reliance on bilateral contracts stayed the same, reliance on spot market purchases increased by 1.7 percentage points and reliance on self-supply decreased by 1.7 percentage points.
- **Supply and Demand: Scarcity.** In 2014, shortage pricing was triggered on two days. On January 6, shortage pricing was triggered by a voltage reduction action that was issued at 1950 EPT and terminated at 2045. On January 7, shortage pricing was triggered by shortage of primary and synchronized reserves starting in the hour beginning 0700 EPT and was in effect until 1220 during the morning peak as well as between 1755 and 1810 during the evening peak.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.1 percent in 2013 to 0.2 percent in 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 2013 to 0.5 percent in 2014.

  In 2014, 13 control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.
- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 3.1 percent in 2013 to 0.4 percent in 2014. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 2.5 percent in 2013 to 0.3 percent in 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 2014, 75.6 percent of marginal units had an average markup index less than or equal to 0.0. In 2014, 11.3 percent of units had average dollar markups greater than or equal to $150. In 2013, only 4.3 percent of units had average dollar markups greater than or equal to $150. Markups increased during the high demand days in January.

  In the PJM Day-Ahead Energy Market in 2014, 87.1 percent of marginal units had an average markup index less than or equal to 0.0. In 2014, 2.7 percent of units had average dollar markups greater than or equal to $150. In 2013, less than 0.1 percent of units had average dollar markups greater than or equal to $150. Markups increased during the high demand days in January.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 112 units eligible for FMU or AU status in at least one month during 2014, 4 units (3.5 percent) were FMUs or AUs for all months, and 21 units (18.8 percent) qualified in only one month. A new FMU rule became effective November 1, 2014, limiting the availability of FMU adders to units with net revenues less than unit going forward costs.
- **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 in the first part of the year, 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 subsequently 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 2014, 56.1 percent were offered as available for economic dispatch, 22.9 percent were offered as self scheduled, and 21.0 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 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 2014 compared to 2013. The load-weighted average real-time LMP was 37.4 percent higher in 2014 than in 2013, $53.14 per MWh versus $38.66 per MWh.

  PJM Day-Ahead Energy Market prices increased in 2014 compared to 2013. The load-weighted average day-ahead LMP was 37.8 percent higher in 2014 than in 2013, $53.62 per MWh versus $38.93 per MWh.[7]

- **Components of LMP.** In the PJM Real-Time Energy Market, for 2014, 33.4 percent of the load-weighted LMP was the result of coal costs, 35.2 percent was the result of gas costs and 0.7 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market for 2014, 21.1 percent of the load-weighted LMP was the result of the coal costs, 19.9 percent was the result of gas costs, 11.6 percent was the result of the up-to congestion transaction cost, 17.2 percent was the result of the DEC costs and 15.2 percent was the result of the INC costs.

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

  In the PJM Real-Time Energy Market in 2014, the adjusted markup component of LMP was $3.32 per MWh or 6.2 percent of the PJM real-time, load-weighted average LMP. The month of March had the highest adjusted markup component, $8.21 per MWh, or 10.82 percent of the real-time load-weighted average LMP, a substantial increase over 2013. In 2013, the adjusted markup was $1.16 per MWh or 3.00 percent of the PJM real-time load-weighted average LMP.

  In the PJM Day-Ahead Energy Market, marginal INCs, DECs and UTCs have zero markups. In 2014, the adjusted markup component of LMP resulting from generation resources was $0.94 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 the first quarter 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

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 *2014 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

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the average day-ahead and real-time prices was -$0.60 per MWh 2013 and -$0.93 per MWh in 2014. The difference between average day-ahead and real-time prices, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

- In 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 the adequacy of capacity market incentives, the competitiveness of participant offer behavior under tight market conditions, reasons for the lack of natural gas availability and pricing, the performance and obligations of demand response and the treatment of interchange transactions.

Recommendations

- The MMU recommendeds the elimination of FMU and AU adders. Since the implementation of FMU adders, PJM has undertaken major redesigns of its market rules that affect 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. Status: Adopted partially, Q4, 2014.)

  The MMU and PJM proposed, and on October 31, 2014, the Commission approved, a compromise that limited FMU adders to units with net revenues less than unit going forward costs or ACR.[8]
- 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. Status: Adopted in full, Q4, 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule transactions. (Priority: Low. First reported 2013. Status: Not adopted.)
- There is currently no PJM documentation in the tariff or manuals explaining how hubs are created

8 149 FERC ¶ 61,091 (2014).

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

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. Status: Not adopted.)

- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- The MMU recommends that generation owners be permitted to submit cost-based offers above the $1,000/MWh energy offer cap if they are calculated in accordance with PJM's Cost Development Guidelines excluding the ten percent adder, subject to after the fact review by the MMU. Such offers should be allowed to set LMP. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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, 2010. Status: Not adopted.)

10 The general definition of a hub can be found in PJM. "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.

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in 2014, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

Average real-time offered generation decreased by 4,715 MW in the summer of 2014 compared to the summer 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 in 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

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transmission constraints.[12] This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.

PJM also offer caps units that are committed for reliability reasons in addition to units committed to provide constraint relief. Specifically, units that are committed to provide reactive support and black start service are offer capped in the energy market. These units are committed manually in both the Day-Ahead and Real-Time Energy Markets. Before 2011, these units were generally economic in the energy market. Since 2011, the percentage of hours when these units were not economic in the Real-Time Energy Market has steadily increased. In the Day-Ahead Energy Market, PJM started to commit these units as offer capped in September 2012, as part of a broader effort to maintain consistency between Real-Time and Day-Ahead Energy Markets.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Nonetheless, with a market design that includes a direct and explicit scarcity pricing revenue true up mechanism, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power. PJM implemented scarcity pricing rules in 2012. There are significant issues with the scarcity pricing net revenue true up mechanism in the PJM scarcity pricing design, which will create issues when scarcity pricing occurs.

The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case during the high demand hours in the first quarter. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods in the first quarter 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 2014.

Market Structure

Market Concentration

Analyses of supply curve segments of the PJM Energy Market in 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.

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

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.

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 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 2014 was moderately concentrated (Table 3-2).

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

	Hourly Market HHI (2013)	Hourly Market HHI (2014)
Average	1167	1153
Minimum	844	930
Maximum	1604	1468
Highest market share (One hour)	31%	29%
Average of the highest hourly market share	22%	21%
# Hours	8,760	8,760
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

14 77 FERC ¶ 61,263, pp. 64-70 (1996), *"Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement."*

15 This analysis includes all hours in 2014, regardless of congestion.

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

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

	2013			2014		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	878	1064	1464	1031	1182	1484
Intermediate	946	2527	9194	795	1919	7307
Peak	580	6397	10000	643	5959	10000

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

Figure 3-1 Fuel source distribution in unit segments: 2014

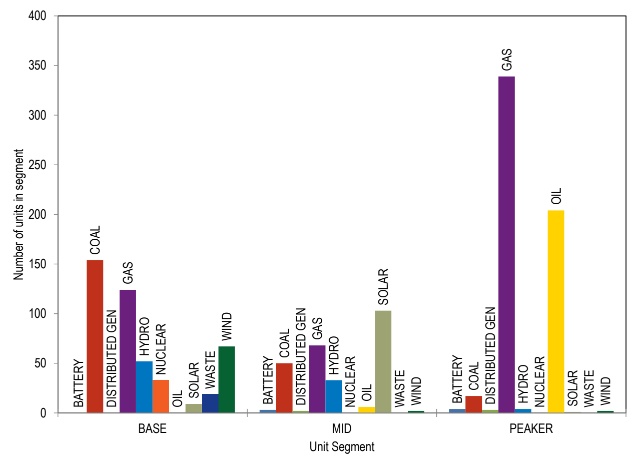
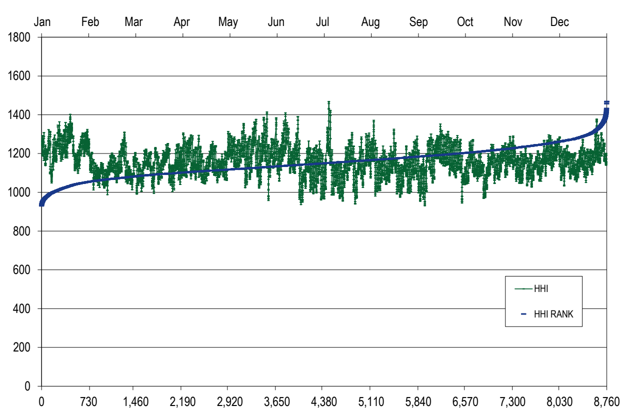


Figure 3-2 presents the hourly HHI values in chronological order and an HHI duration curve for 2014.

Figure 3-2 PJM hourly Energy Market HHI: 2014



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Ownership of Marginal Resources

Table 3-4 shows the contribution to 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 2014, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. The results show that in 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 55.1 percent of the real-time, load-weighted, average PJM system LMP. During 2013, the offers of one company contributed 22.3 percent of the real time, load-weighted PJM system LMP and offers of the top four companies contributed 61.7 percent of the real-time, load-weighted, average PJM system LMP.

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

2013		2014	
Company	Percent of Price	Company	Percent of Price
1	22.3%	1	17.1%
2	22.2%	2	17.1%
3	10.7%	3	12.6%
4	6.5%	4	8.3%
5	4.5%	5	5.8%
6	4.3%	6	5.6%
7	3.7%	7	4.8%
8	3.2%	8	3.5%
9	2.8%	9	3.1%
Other (59 companies)	19.7%	Other (62 companies)	22.2%

Table 3-5 shows the contribution to 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 (22.5 percent), in 2013 also had the largest impact (14.3 percent) in 2014.

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

2013		2014	
Company	Percent of Price	Company	Percent of Price
1	22.5%	1	14.3%
2	8.9%	2	8.6%
3	8.4%	3	6.9%
4	8.2%	4	6.2%
5	7.8%	5	4.9%
6	4.1%	6	4.1%
7	3.2%	7	3.5%
8	3.1%	8	2.7%
9	2.4%	9	2.5%
Other (146 companies)	31.4%	Other (152 companies)	46.4%

Type of Marginal Resources

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. Marginal resource designation is not limited to physical resources 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 2014, coal units were 52.90 percent and natural gas units were 35.80 percent of marginal resources. In 2013, coal units were 56.94 percent and natural gas units were 34.72 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 2014, 75.25 percent of the wind marginal units had negative offer prices, 22.20 percent had zero offer prices and 2.55 percent had positive offer prices.

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

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

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.

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

Type/Fuel	2013	2014
Coal	56.94%	52.90%
Gas	34.72%	35.80%
Oil	3.27%	7.45%
Wind	4.76%	3.29%
Other	0.20%	0.43%
Municipal Waste	0.07%	0.05%
Uranium	0.02%	0.04%
Emergency DR	0.02%	0.04%

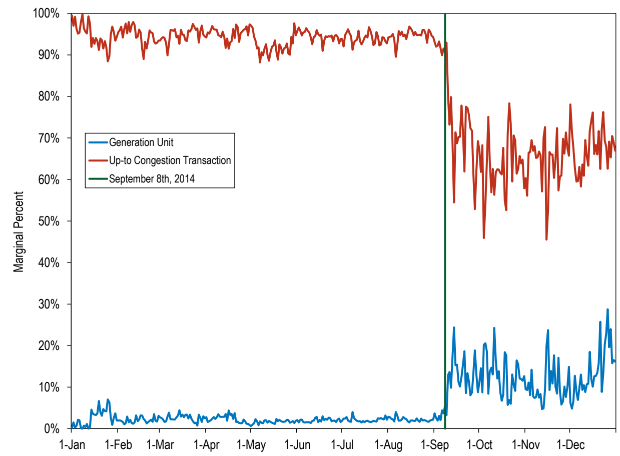
Table 3-7 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In 2014, up-to congestion transactions were 90.87 percent of the total marginal resources. Up-to congestion transactions were 96.33 percent of the total marginal resources in 2013.

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

Type/Fuel	2013	2014
Up-to Congestion Transaction	96.33%	90.87%
DEC	1.27%	3.27%
INC	1.05%	2.28%
Coal	0.77%	2.02%
Gas	0.36%	1.16%
Wind	0.15%	0.18%
Dispatchable Transaction	0.05%	0.08%
Price Sensitive Demand	0.01%	0.01%
Municipal Waste	0.00%	0.01%
Oil	0.00%	0.05%
Import	0.00%	0.04%
Other	0.00%	0.02%
Total	100.00%	100.00%

Figure 3-3 shows, for the day-ahead market in 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 that date.[19] The percentage of marginal up-to congestion transaction decreased and that of generation units increased.

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

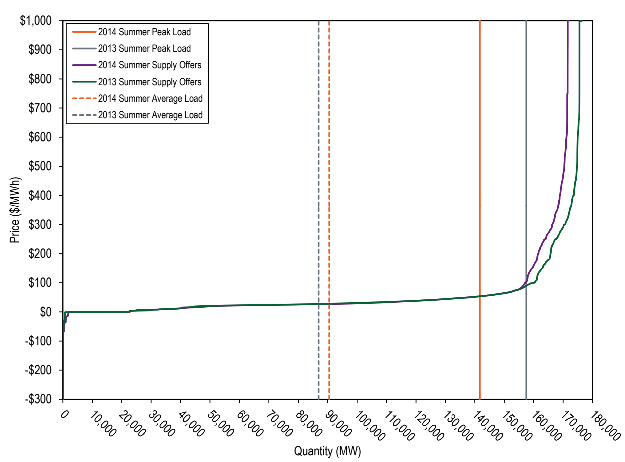


Supply

Supply includes physical generation and imports and virtual transactions.

Figure 3-4 shows the average PJM aggregate real-time generation supply curves by offer price, peak load and average load for summer of 2013 and 2014. Total average PJM aggregate real-time generation supply decreased by 4,715 MW, or 2.7 percent, in 2014 from an average maximum of 176,316 MW to 171,602 MW.

Figure 3-4 Average PJM aggregate real-time generation supply curves by offer price: Summer of 2013 and 2014



19 See 18 CFR § 385.213 (2014).

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Energy Production by Fuel Source

In 2014, generation from coal units decreased 1.3 percent and generation from natural gas units increased 7.6 percent from 2013 (Table 3-8).[20] Natural gas prices increased in 2014, especially in the eastern part of PJM. Comparing fuel prices in 2014 to 2013, the price of Northern Appalachian coal remained constant; the price of Central Appalachian coal was 3.6 percent lower; the price of Powder River Basin coal was 9.3 percent higher; the price of eastern natural gas was 36.1 percent higher; and the price of western natural gas was 17.4 percent higher.

Table 3-8 PJM generation (By fuel source (GWh)): 2013 and 2014[21]

	2013		2014		Change in
	Gwh	Percent	GWh	Percent	Output
Coal	356,018.0	44.5%	351,456.5	43.5%	(1.3%)
Standard Coal	346,188.8	43.3%	341,538.6	42.3%	(1.3%)
Waste Coal	9,829.2	1.2%	9,918.0	1.2%	0.9%
Nuclear	277,277.8	34.7%	277,635.6	34.3%	0.1%
Gas	130,230.9	16.3%	140,076.4	17.3%	7.6%
Natural Gas	127,855.5	16.0%	137,503.6	17.0%	7.5%
Landfill Gas	2,321.0	0.3%	2,369.4	0.3%	2.1%
Biomass Gas	54.5	0.0%	203.5	0.0%	273.3%
Hydroelectric	14,116.4	1.8%	14,394.3	1.8%	2.0%
Pumped Storage	6,690.4	0.8%	7,138.7	0.9%	6.7%
Run of River	7,426.0	0.9%	7,255.5	0.9%	(2.3%)
Wind	14,854.1	1.9%	15,540.5	1.9%	4.6%
Waste	5,040.1	0.6%	5,472.4	0.7%	8.6%
Solid Waste	4,185.0	0.5%	4,566.5	0.6%	9.1%
Miscellaneous	855.1	0.1%	905.9	0.1%	5.9%
Oil	1,948.5	0.2%	3,299.9	0.4%	69.4%
Heavy Oil	1,730.7	0.2%	2,742.1	0.3%	58.4%
Light Oil	187.2	0.0%	480.0	0.1%	156.5%
Diesel	14.8	0.0%	52.5	0.0%	253.6%
Kerosene	15.7	0.0%	25.3	0.0%	61.3%
Jet Oil	0.1	0.0%	0.1	0.0%	(38.6%)
Solar, Net Energy Metering	355.0	0.0%	404.6	0.0%	13.7%
Battery	0.7	0.0%	6.5	0.0%	807.7%
Total	799,841.7	100.0%	808,286.8	100.0%	1.1%

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

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

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Table 3-9 Monthly PJM generation (By fuel source (GWh)): 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	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	23,144.8	27,219.8	27,965.6	351,456.5
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	22,617.7	26,440.0	27,244.3	341,538.6
Waste Coal	1,024.1	859.5	890.7	777.7	758.2	881.6	929.7	909.2	859.2	527.1	779.8	721.2	9,918.0
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	22,351.1	22,648.8	25,465.1	277,635.6
Gas	11,600.8	9,772.7	11,057.0	8,393.0	10,716.0	12,490.2	13,860.5	14,158.6	13,159.3	11,086.4	10,661.0	13,120.8	140,076.4
Natural Gas	11,380.2	9,567.1	10,849.0	8,185.7	10,508.7	12,274.8	13,638.7	13,946.5	12,934.7	10,870.8	10,457.8	12,889.7	137,503.6
Landfill Gas	207.4	181.3	194.5	197.3	206.4	196.4	199.7	206.4	197.6	185.1	189.6	207.6	2,369.4
Biomass Gas	13.2	24.3	13.5	10.1	1.0	19.0	22.1	5.7	27.1	30.5	13.6	23.5	203.5
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	845.9	782.9	1,164.5	14,394.3
Pumped Storage	536.0	530.6	551.0	433.3	606.2	794.5	832.8	857.0	600.7	505.6	443.0	448.1	7,138.7
Run of River	855.3	543.7	821.0	1,015.6	969.2	585.5	398.8	400.6	269.4	340.3	339.9	716.3	7,255.5
Wind	1,918.4	1,919.4	1,920.4	1,921.4	1,922.4	1,923.4	1,924.4	1,925.4	1,926.4	1,927.4	1,928.4	1,929.4	23,087.3
Waste	431.8	358.9	458.7	446.2	465.6	486.4	496.3	512.1	457.3	435.3	457.1	466.6	5,472.4
Solid Waste	348.4	292.3	366.9	374.9	394.8	404.0	418.7	418.3	390.4	369.6	390.1	398.0	4,566.5
Miscellaneous	83.4	66.6	91.7	71.3	70.8	82.4	77.6	93.8	66.9	65.7	67.0	68.6	905.9
Oil	844.2	69.4	200.2	31.8	173.6	250.2	541.0	463.5	243.6	298.0	141.3	43.2	3,299.9
Heavy Oil	585.2	39.0	132.2	25.1	145.4	231.1	510.2	449.1	233.6	275.2	93.0	23.0	2,742.1
Light Oil	193.4	28.7	64.4	6.4	27.8	18.6	30.1	11.7	9.0	22.4	48.1	19.3	480.0
Diesel	47.3	0.5	1.0	0.0	0.2	0.2	0.2	1.1	0.8	0.4	0.1	0.5	52.5
Kerosene	18.4	1.1	2.5	0.3	0.1	0.2	0.4	1.6	0.2	0.0	0.1	0.5	25.3
Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Solar, Net Energy Metering	16.5	20.8	32.3	43.8	42.2	45.8	48.8	45.3	38.9	31.3	23.9	15.0	404.6
Battery	0.2	0.1	0.2	4.6	0.2	0.1	0.1	0.1	0.1	0.2	0.2	0.3	6.5
Total	79,226.2	69,798.5	71,895.7	59,092.8	60,391.6	69,875.4	74,103.8	72,493.3	64,802.1	60,120.3	63,863.4	70,170.6	815,833.6

Net Generation and Load

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

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

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

Real-Time Supply

Average offered real-time generation decreased by 4,715 MW, or 2.7 percent, in summer of 2014 from an average maximum of 176,316 MW in summer of 2013 to 171,602 MW in summer of 2014.[22] In 2014, 2,659 MW of new capacity were added to PJM. This new generation was more than offset by the deactivation of 29 units (2,949.3 MW) since January 1, 2014.

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

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PJM average real-time generation in 2014 increased by 0.2 percent from 2013, from 89,769 MW to 89,966 MW. PJM average real-time generation in 2014 would have increased by 1.4 percent from 2013, from 90,432 MW to 91,701 MW, if the EKPC Transmission Zone had not been included in the comparison.[23,24]

PJM average real-time supply including imports increased by 0.5 percent in 2014 from 2013, from 94,833 MW to 95,323 MW. PJM average real-time supply, including imports would have increased by 1.0 percent, from 94,190 MW to 95,110 MW, if the EKPC Transmission Zone had not been included in the comparison.

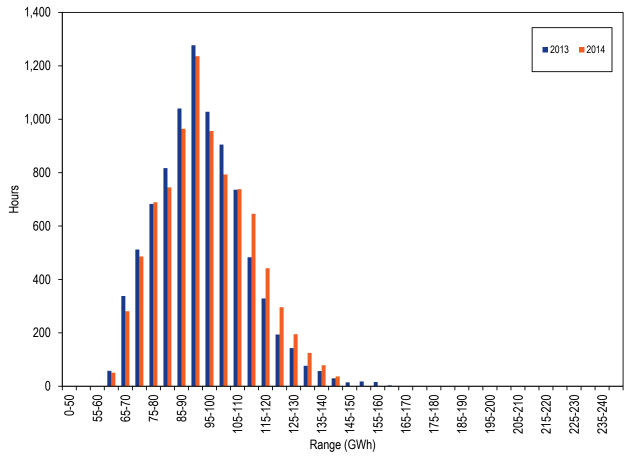
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **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 Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Supply Duration

Figure 3-5 shows the hourly distribution of PJM real-time generation plus imports for 2013 and 2014.

Figure 3-5 Distribution of PJM real-time generation plus imports: 2013 and 2014[25]



PJM Real-Time, Average Supply

Table 3-10 presents summary real-time supply statistics for each year for the 15-year period from 2000 through 2014.[26]

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

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2000	30,301	4,980	33,256	5,456	NA	NA	NA	NA
2001	29,553	4,937	32,552	5,285	(2.5%)	(0.9%)	(2.1%)	(3.1%)
2002	34,928	7,535	38,535	7,751	18.2%	52.6%	18.4%	46.7%
2003	36,628	6,165	40,205	6,162	4.9%	(18.2%)	4.3%	(20.5%)
2004	51,068	13,790	55,781	14,652	39.4%	123.7%	38.7%	137.8%
2005	81,127	15,452	86,353	15,981	58.9%	12.0%	54.8%	9.1%
2006	82,780	13,709	86,978	14,402	2.0%	(11.3%)	0.7%	(9.9%)
2007	85,860	14,018	90,351	14,763	3.7%	2.3%	3.9%	2.5%
2008	83,476	13,787	88,899	14,256	(2.8%)	(1.7%)	(1.6%)	(3.4%)
2009	78,026	13,647	83,058	14,140	(6.5%)	(1.0%)	(6.6%)	(0.8%)
2010	82,585	15,556	87,386	16,227	5.8%	14.0%	5.2%	14.8%
2011	85,775	15,932	90,511	16,759	3.9%	2.4%	3.6%	3.3%
2012	88,708	15,701	94,083	16,505	3.4%	(1.4%)	3.9%	(1.5%)
2013	89,769	15,012	94,833	15,878	1.2%	(4.4%)	0.8%	(3.8%)
2014	89,966	14,539	95,323	15,579	0.2%	(3.2%)	0.5%	(1.9%)

23 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.

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

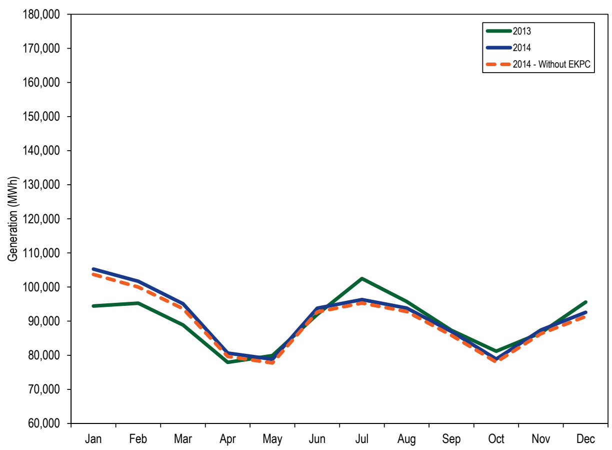
25 Each range on the horizontal axis excludes the start value and includes the end value.

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

PJM Real-Time, Monthly Average Generation

Figure 3-6 compares the real-time, monthly average hourly generation in 2013 and 2014 with and without EKPC.

Figure 3-6 PJM real-time average monthly hourly generation: 2013 and 2014



Day-Ahead Supply

PJM average day-ahead supply in 2014, including INCs and up-to congestion transactions, decreased by 6.9 percent from 2013, from 148,323 MW to 138,040 MW. The PJM average day-ahead supply in 2014, including INCs and up-to congestion transactions, would have decreased by 7.4 percent in 2014, from 148,323 MW to 137,408 MW, if the EKPC Transmission Zone had not been included in the comparison.

PJM average day-ahead supply in 2014, including INCs, up-to congestion transactions, and imports, decreased by 6.9 percent from 2013, from 150,595 MW to 140,239 MW. PJM average day-ahead supply in 2014, including INCs, up-to congestion transactions, and imports, would have decreased by 7.3 percent from 2013, from 150,595 MW to 139,607 MW, if the EKPC Transmission Zone had not been included in the comparison.

While up-to congestion transactions (UTC) continued to displace increment offers and decrement bids in the first part of the year, 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.[27]

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 3-7 shows the hourly distribution of PJM day-ahead supply, including increment offers, up-to congestion transactions, and imports for 2013 and 2014.

27 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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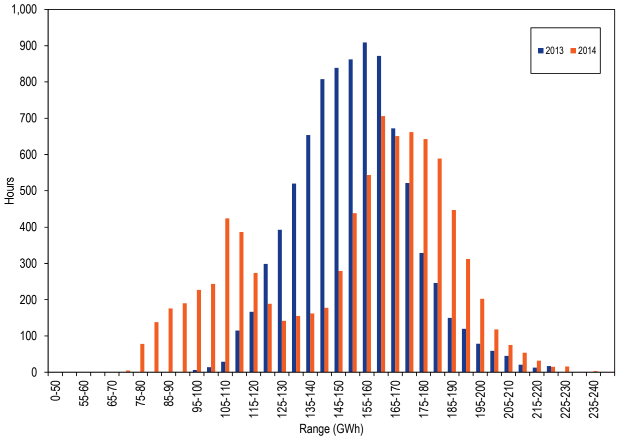
Figure 3-7 Distribution of PJM day-ahead supply plus imports: 2013 and 2014[28]



PJM Day-Ahead, Average Supply

Table 3-11 presents summary day-ahead supply statistics for each year of the 15-year period from 2000 through 2014.[29]

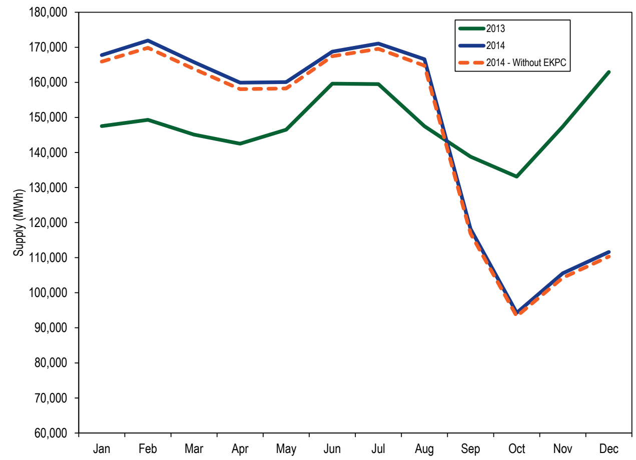
Table 3-11 PJM day-ahead average hourly supply and day-ahead average hourly supply plus average hourly imports: 2000 through 2014

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2000	27,135	4,858	27,589	4,895	NA	NA	NA	NA
2001	26,762	4,595	27,497	4,664	(1.4%)	(5.4%)	(0.3%)	(4.7%)
2002	31,434	10,007	31,982	10,015	17.5%	117.8%	16.3%	114.7%
2003	40,642	8,292	41,183	8,287	29.3%	(17.1%)	28.8%	(17.3%)
2004	62,755	17,141	63,654	17,362	54.4%	106.7%	54.6%	109.5%
2005	94,438	17,204	96,449	17,462	50.5%	0.4%	51.5%	0.6%
2006	100,056	16,543	102,164	16,559	5.9%	(3.8%)	5.9%	(5.2%)
2007	108,707	16,549	111,023	16,729	8.6%	0.0%	8.7%	1.0%
2008	105,485	15,994	107,885	16,136	(3.0%)	(3.4%)	(2.8%)	(3.5%)
2009	97,388	16,364	100,022	16,397	(7.7%)	2.3%	(7.3%)	1.6%
2010	107,307	21,655	110,026	21,837	10.2%	32.3%	10.0%	33.2%
2011	117,130	20,977	119,501	21,259	9.2%	(3.1%)	8.6%	(2.6%)
2012	134,479	17,905	136,903	18,080	14.8%	(14.6%)	14.6%	(15.0%)
2013	148,323	18,783	150,595	18,978	10.3%	4.9%	10.0%	5.0%
2014	138,040	34,833	140,239	35,050	(6.9%)	85.5%	(6.9%)	84.7%

PJM Day-Ahead, Monthly Average Supply

Figure 3-8 compares the day-ahead, monthly average hourly supply, including increment offers and up-to congestion transactions, in 2013 and 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.[30]

Figure 3-8 PJM day-ahead monthly average hourly supply: 2013 and 2014



Real-Time and Day-Ahead Supply

Table 3-12 presents summary statistics for 2013 and 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 2014 up-to congestion transactions were 25.4 percent of the total day-ahead supply compared to 34.3 percent in 2013.

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

29 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.

30 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): 2013 and 2014

		Day Ahead					Real Time		Day Ahead Less Real Time	
	Year	Generation	INC Offers	Up-to Congestion	Imports	Total Supply	Generation	Total Supply	Total Supply	Total Generation
Average	2013	91,593	5,131	51,598	2,273	150,595	89,769	94,833	55,763	1,825
	2014	91,465	3,663	33,078	2,158	130,365	88,909	94,217	36,148	2,557
Median	2013	90,767	5,099	51,992	2,249	150,475	88,721	93,518	56,957	2,046
	2014	90,357	3,619	14,272	2,154	120,026	87,476	92,708	27,318	2,881
Standard Deviation	2013	16,059	856	10,061	429	18,978	15,012	15,878	3,101	1,046
	2014	14,523	933	27,719	457	34,324	13,734	14,764	19,561	789
Peak Average	2013	101,479	5,369	52,246	2,374	161,468	98,622	104,192	57,276	2,857
	2014	100,465	4,224	33,841	2,344	140,874	96,871	102,875	37,999	3,594
Peak Median	2013	99,284	5,420	53,079	2,366	159,563	96,660	102,041	57,523	2,625
	2014	98,565	4,222	15,210	2,354	127,621	95,102	101,063	26,559	3,463
Peak Standard Deviation	2013	13,183	799	9,563	370	15,798	12,706	13,606	2,192	477
	2014	11,721	814	27,057	419	33,348	11,580	12,356	20,992	141
Off-Peak Average	2013	82,975	4,923	51,033	2,184	141,116	82,050	86,673	54,443	925
	2014	83,649	3,176	32,415	1,997	121,238	81,993	86,697	34,541	1,656
Off-Peak Median	2013	81,764	4,892	51,070	2,092	140,236	80,697	85,164	55,072	1,067
	2014	82,668	3,101	12,679	1,954	107,939	80,596	85,148	22,790	2,072
Off-Peak Standard Deviation	2013	13,105	849	10,444	456	16,239	12,378	12,944	3,295	727
	2014	11,973	736	28,266	427	32,503	11,537	12,370	20,132	436

Figure 3-9 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 3-9 Day-ahead and real-time supply (Average hourly volumes): 2014

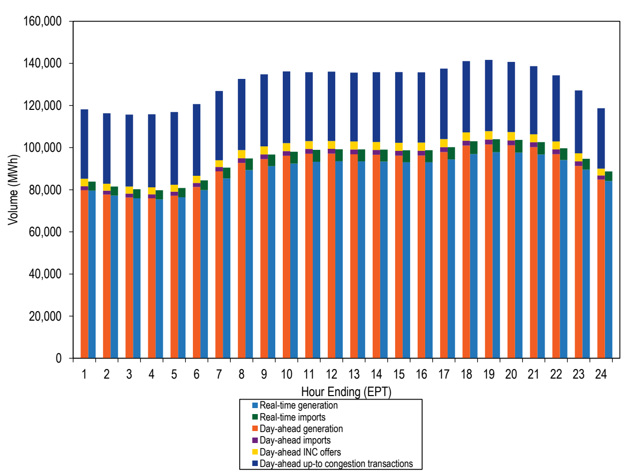

Figure 3-10 shows the difference between the day-ahead and real-time average daily supply in 2013 and 2014.

Figure 3-10 Difference between day-ahead and real-time supply (Average daily volumes): 2013 and 2014

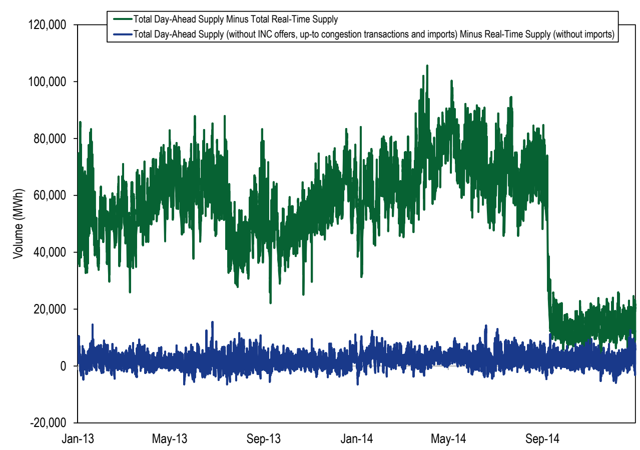

Figure 3-11 shows the difference between the PJM real-time generation and real-time load by zone in 2014. Table 3-13 shows the difference between the PJM real-time generation and real-time load by zone in 2013 and 2014. Figure 3-11 is color coded on a scale on which red shades represent zones that have 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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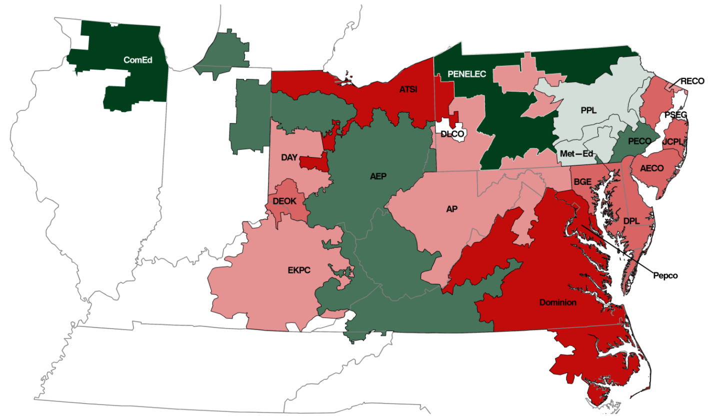
Figure 3-11 Map of PJM real-time generation less real-time load by zone: 2014[31]



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	(6,957)	ComEd	28,592	DPL	(10,865)	PENELEC	27,531
AEP	19,292	DAY	(2,668)	EKPC	(2,419)	Pepco	(18,671)
AP	(2,266)	DEOK	(7,196)	JCPL	(9,782)	PPL	8,250
ATSI	(14,277)	DLCO	3,324	Met-Ed	6,543	PSEG	2,013
BGE	(10,598)	Dominion	(12,862)	PECO	20,234	RECO	(1,493)

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

	Zonal Generation and Load (GWh)					
	2013			2014		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	2,219.5	10,397.8	(8,178.4)	3,296.0	10,252.7	(6,956.6)
AEP	133,130.2	129,477.6	3,652.6	148,249.6	128,957.3	19,292.3
AP	54,539.3	47,223.6	7,315.7	46,089.7	48,355.4	(2,265.7)
ATSI	55,061.7	66,818.8	(11,757.1)	53,453.7	67,730.8	(14,277.1)
BGE	21,794.6	32,196.1	(10,401.4)	21,368.7	31,967.1	(10,598.4)
ComEd	127,235.2	98,548.9	28,686.3	126,274.9	97,683.0	28,591.9
DAY	17,047.5	16,739.6	307.9	14,342.8	17,011.2	(2,668.4)
DEOK	24,845.3	26,656.0	(1,810.7)	19,823.2	27,019.7	(7,196.5)
DLCO	17,650.0	14,674.3	2,975.7	17,735.1	14,411.1	3,324.0
Dominion	80,988.9	93,863.4	(12,874.5)	82,444.7	95,306.3	(12,861.6)
DPL	7,575.3	18,459.1	(10,883.8)	7,514.5	18,379.3	(10,864.7)
EKPC	5,629.8	7,085.0	(1,455.2)	10,384.4	12,803.0	(2,418.6)
JCPL	11,145.3	23,012.3	(11,867.0)	12,976.5	22,758.7	(9,782.2)
Met-Ed	19,937.3	15,090.7	4,846.5	21,625.3	15,082.6	6,542.7
PECO	60,062.2	40,127.2	19,935.0	60,038.1	39,803.7	20,234.4
PENELEC	43,582.3	17,225.2	26,357.1	44,805.9	17,274.8	27,531.1
Pepco	9,264.6	30,416.0	(21,151.4)	11,775.6	30,446.7	(18,671.1)
PPL	49,475.8	40,560.9	8,914.8	49,135.5	40,885.7	8,249.8
PSEG	45,189.5	43,686.4	1,503.0	44,896.7	42,883.6	2,013.1
RECO	0.0	1,530.8	(1,530.8)	0.0	1,492.7	(1,492.7)

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 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 2013, which 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 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 2013.

The PJM system peak load during the first three months of 2014 was 140,467 MW in HE 1900 on January 7, 2014, which was 13,835 MW, or 10.9 percent, higher than the PJM peak for the first three months of 2013 of 126,632 MW in HE 19 on January 22, 2013.

Table 3-14 shows the peak loads for years 1999 through 2014.

31 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 1/29/2015)

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Table 3-14 Actual PJM footprint peak loads: 1999 to 2014[32]

	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 3-12 shows the peak loads for the years 1999 through 2014.

Figure 3-12 PJM footprint calendar year peak loads: 1999 to 2014

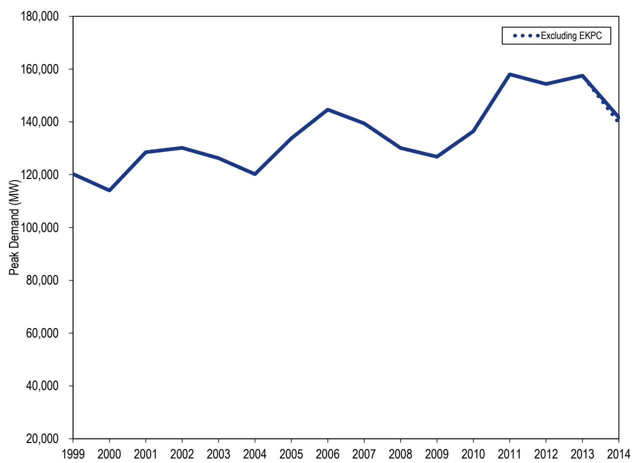
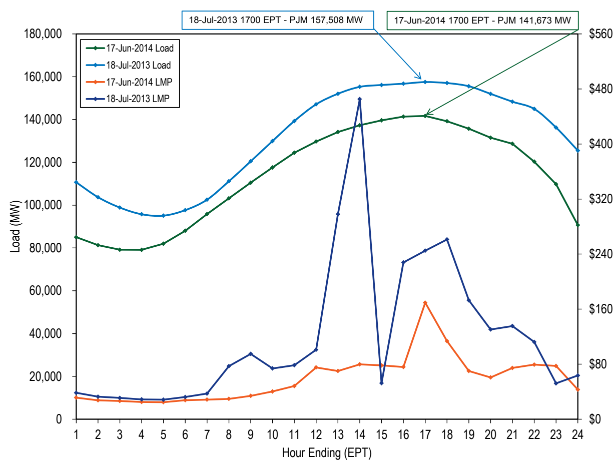


Figure 3-13 compares the peak load days 2013 and 2014. The average hourly real-time LMP peaked at $169.33 on June 17, 2014 and peaked at $465.18 on July 18, 2013.

Figure 3-13 PJM peak-load comparison: Tuesday, June 17, 2014, and Tuesday, July 18, 2013



Real-Time Demand

PJM average real-time load in 2014 increased by 0.9 percent from 2013, from 88,332 MW to 89,099 MW. PJM average real-time load in 2014 would have increased by 0.1 percent from 2013, from 88,332 MW to 88,456 MW, if the EKPC Transmission Zone had not been included in the comparison.[33,34]

PJM average real-time demand in 2014 increased 1.7 percent from 2013, from 92,879 MW to 94,471 MW. PJM average real-time demand in 2014 would have

32 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>.

33 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.

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

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increased by 1.0 percent from 2013, from 92,879 MW to 94,471 MW, if the EKPC Transmission Zone had not been included in the comparison.

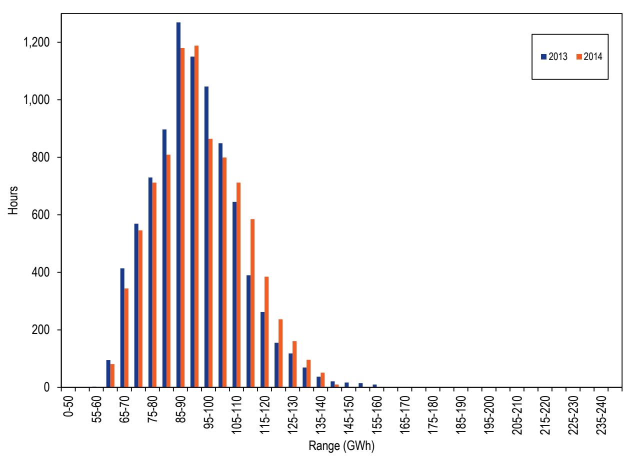
In the PJM Real-Time Energy Market, there are two types of demand:

- **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 Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Demand Duration

Figure 3-14 shows the hourly distribution of PJM real-time load plus exports for 2013 and 2014.[35]

Figure 3-14 Distribution of PJM real-time accounting load plus exports: 2013 and 2014[36]



PJM Real-Time, Average Load

Table 3-15 presents summary real-time demand statistics for 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.[37]

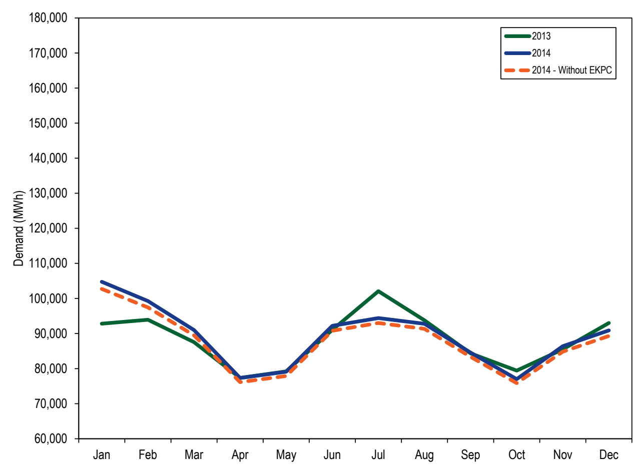
Table 3-15 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: 1998 through 2014[38]

	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
1998	28,578	5,511	28,578	5,511	NA	NA	NA	NA
1999	29,641	5,955	29,641	5,955	3.7%	8.1%	3.7%	8.1%
2000	30,113	5,529	31,341	5,728	1.6%	(7.2%)	5.7%	(3.8%)
2001	30,297	5,873	32,165	5,564	0.6%	6.2%	2.6%	(2.9%)
2002	35,776	7,976	37,676	8,145	18.1%	35.8%	17.1%	46.4%
2003	37,395	6,834	39,380	6,716	4.5%	(14.3%)	4.5%	(17.5%)
2004	49,963	13,004	54,953	14,947	33.6%	90.3%	39.5%	122.6%
2005	78,150	16,296	85,301	16,546	56.4%	25.3%	55.2%	10.7%
2006	79,471	14,534	85,696	15,133	1.7%	(10.8%)	0.5%	(8.5%)
2007	81,681	14,618	87,897	15,199	2.8%	0.6%	2.6%	0.4%
2008	79,515	13,758	86,306	14,322	(2.7%)	(5.9%)	(1.8%)	(5.8%)
2009	76,034	13,260	81,227	13,792	(4.4%)	(3.6%)	(5.9%)	(3.7%)
2010	79,611	15,504	85,518	15,904	4.7%	16.9%	5.3%	15.3%
2011	82,541	16,156	88,466	16,313	3.7%	4.2%	3.4%	2.6%
2012	87,011	16,212	92,135	16,052	5.4%	0.3%	4.1%	(1.6%)
2013	88,332	15,489	92,879	15,418	1.5%	(4.5%)	0.8%	(3.9%)
2014	89,099	15,763	94,471	15,677	0.9%	1.8%	1.7%	1.7%

PJM Real-Time, Monthly Average Load

Figure 3-15 compares the real-time, monthly average hourly loads in 2013 and 2014 with and without EKPC.

Figure 3-15 PJM real-time monthly average hourly load: 2013 and 2014



35 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>.

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

37 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.

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

PJM real-time load is significantly affected by temperature. Figure 3-16 and Table 3-16 compare the PJM monthly heating and cooling degree days in 2014 with those in 2013.[39] Cooling degree days decreased by 9.6 percent from 2013 to 2014, while heating degree days increased 9.4 percent from 2013 to 2014.

Figure 3-16 PJM heating and cooling degree days: 2013 and 2014

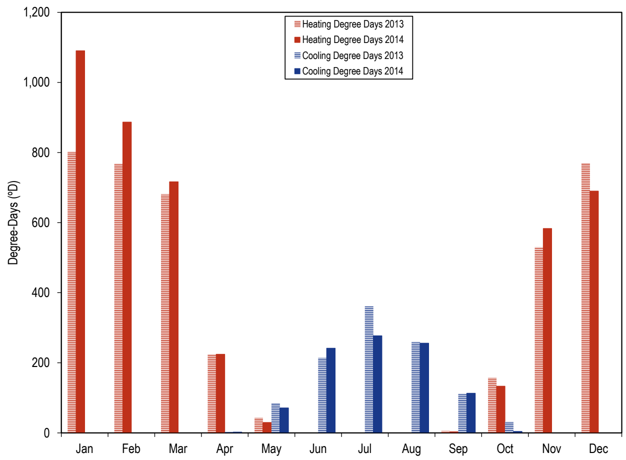


Table 3-16 PJM heating and cooling degree days: 2013 and 2014

	2013		2014		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	803	0	1,090	0	35.8%	0.0%
Feb	767	0	887	0	15.6%	0.0%
Mar	681	0	716	0	5.2%	0.0%
Apr	224	3	224	2	(0.0%)	(20.5%)
May	43	86	30	71	(31.1%)	(16.7%)
Jun	0	215	0	242	0.0%	12.4%
Jul	0	361	0	277	0.0%	(23.2%)
Aug	0	259	0	256	0.0%	(1.2%)
Sep	6	113	3	113	(47.2%)	0.5%
Oct	157	32	133	4	(15.0%)	(87.0%)
Nov	530	0	583	0	10.0%	0.0%
Dec	769	0	690	0	(10.3%)	0.0%
Total	3,982	1,069	4,358	966	9.4%	(9.6%)

39 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings).
Heating and cooling degree days are calculated by weighting the temperature at each weather station in the individual transmission zones using weights provided by PJM in Manual 19. Then the temperature is weighted by the real-time zonal accounting load for each transmission zone. After calculating an average daily temperature across PJM, the heating and cooling degree formulas are used to calculate the daily heating and cooling degree days, which are summed for monthly reporting. The weather stations that provided the basis for the analysis are ABE, ACY, AVP, BWI, CAK, CLE, CMH, CRW, CVG, DAY, DCA, ERI, EWR, FWA, IAD, ILG, IPT, LEX, ORD, ORF, PHL, PIT, RIC, ROA, TOL and WAL.

Day-Ahead Demand

PJM average day-ahead demand 2014, including DECs and up-to congestion transactions, decreased by1.8 percent from 2013, from 144,858 MW to 142,251 MW. The PJM average day-ahead demand in 2014, including DECs and up-to congestion transactions, would have decreased 2.4 percent from 2013, from 144,858 MW to 141,413 MW, if the EKPC Transmission Zone had not been included in the comparison.

PJM average day-ahead demand in 2014, including DECs, up-to congestion transactions, and exports, decreased by 1.4 percent from 2013, from 148,132 MW to 146,120 MW. The PJM average day-ahead demand in 2014, including DECs and up-to congestion transactions, and exports, would have decreased 1.9 percent from 2013, from 148,132 MW to 145,282 MW, if the EKPC Transmission Zone had not been included in the comparison.

While up-to congestion transactions (UTC) continued to displace increment offers and decrement bids in the first part of the year, 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.[40]

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

40 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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analogous to a matched pair of an INC offer and a DEC bid.

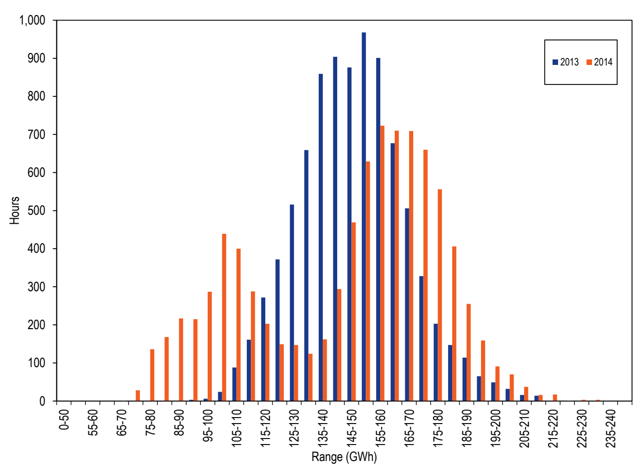
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. An export must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An export energy transaction that clears the Day-Ahead Energy Market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an export energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the Real-Time Energy Market scheduling process.

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

PJM Day-Ahead Demand Duration

Figure 3-17 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up-to congestion transactions, and exports for 2013 and 2014.

Figure 3-17 Distribution of PJM day-ahead demand plus exports: 2013 and 2014[41]



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

PJM Day-Ahead, Average Demand

Table 3-17 presents summary day-ahead demand statistics for each year of the 15-year period 2000 to 2014.[42]

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

	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2000	33,039	6,852	33,411	6,757	NA	NA	NA	NA
2001	33,370	6,562	33,757	6,431	1.0%	(4.2%)	1.0%	(4.8%)
2002	42,305	10,161	42,413	10,208	26.8%	54.9%	25.6%	58.7%
2003	44,674	7,841	44,807	7,811	5.6%	(22.8%)	5.6%	(23.5%)
2004	62,101	16,654	63,455	17,730	39.0%	112.4%	41.6%	127.0%
2005	93,534	17,643	96,447	17,952	50.6%	5.9%	52.0%	1.3%
2006	98,527	16,723	101,592	17,197	5.3%	(5.2%)	5.3%	(4.2%)
2007	105,503	16,686	108,932	17,030	7.1%	(0.2%)	7.2%	(1.0%)
2008	101,903	15,871	105,368	16,119	(3.4%)	(4.9%)	(3.3%)	(5.3%)
2009	94,941	15,869	98,094	15,999	(6.8%)	(0.0%)	(6.9%)	(0.7%)
2010	103,937	21,358	108,069	21,640	9.5%	34.6%	10.2%	35.3%
2011	113,866	20,708	117,681	20,929	9.6%	(3.0%)	8.9%	(3.3%)
2012	131,612	17,421	134,947	17,527	15.6%	(15.9%)	14.7%	(16.3%)
2013	144,858	18,489	148,132	18,570	10.1%	6.1%	9.8%	5.9%
2014	142,251	32,664	146,120	32,671	(1.8%)	76.7%	(1.4%)	75.9%

PJM Day-Ahead, Monthly Average Demand

Figure 3-18 compares the day-ahead, monthly average hourly demand, including decrement bids and up-to congestion transactions, in 2013 and 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.[43]

42 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.

43 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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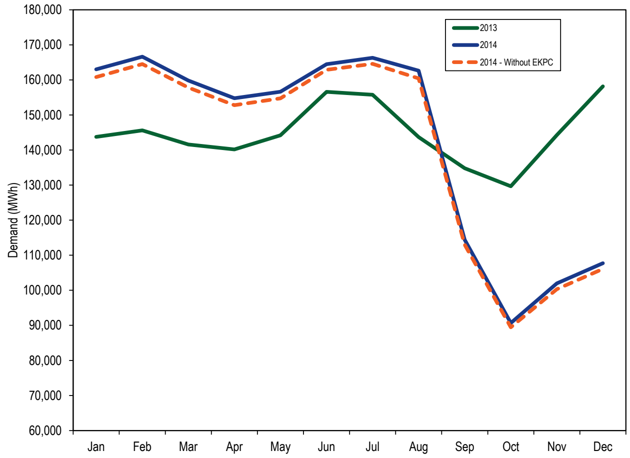
Figure 3-18 PJM day-ahead monthly average hourly demand: 2013 and 2014



Real-Time and Day-Ahead Demand

Table 3-18 presents summary statistics for 2013 and 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.

Figure 3-19 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 3-19 Day-ahead and real-time demand (Average hourly volumes): 2014

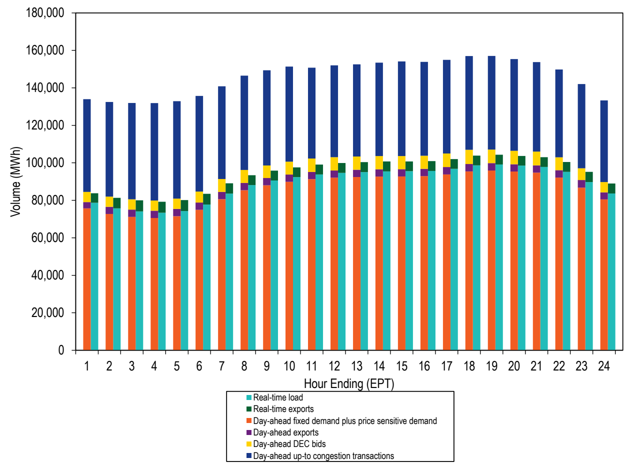


Table 3-18 Cleared day-ahead and real-time demand (MWh): 2013 and 2014

		Day Ahead						Real Time		Day Ahead Less Real Time	
	Year	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Total Demand	Total Load
Average	2013	84,859	1,199	7,202	51,598	3,273	148,132	88,332	92,879	55,253	(6,821)
	2014	85,004	1,212	6,592	49,443	3,869	146,120	89,093	94,465	51,654	(8,250)
Median	2013	83,734	1,229	6,930	51,992	3,231	148,008	87,072	91,572	56,436	(2,108)
	2014	83,546	1,203	6,354	61,205	3,770	155,243	87,436	92,950	62,293	(2,687)
Standard Deviation	2013	14,789	245	1,438	10,061	662	18,570	15,489	15,418	3,152	(384)
	2014	14,908	167	1,490	26,804	926	32,671	15,758	15,672	16,999	(597)
Peak Average	2013	94,149	1,295	7,821	52,246	3,276	158,788	97,624	101,993	56,795	(2,179)
	2014	94,326	1,283	7,408	49,835	3,865	156,718	98,451	103,651	53,067	(2,842)
Peak Median	2013	92,358	1,347	7,516	53,079	3,232	157,103	95,465	99,864	57,240	(6,159)
	2014	92,878	1,277	7,259	61,833	3,783	168,393	97,036	102,457	65,935	(8,302)
Peak Standard Deviation	2013	12,265	257	1,424	9,563	667	15,479	13,105	13,202	2,276	(583)
	2014	12,179	161	1,414	26,095	932	31,555	13,159	13,123	18,432	(819)
Off-Peak Average	2013	76,759	1,115	6,663	51,033	3,271	138,841	80,232	84,933	53,908	(7,058)
	2014	76,890	1,149	5,883	49,102	3,872	136,896	80,948	86,470	50,425	(8,431)
Off-Peak Median	2013	75,503	1,144	6,422	51,070	3,230	138,112	78,751	83,509	54,602	(2,104)
	2014	75,237	1,142	5,658	60,731	3,762	149,205	79,055	84,726	64,478	(2,676)
Off-Peak Standard Deviation	2013	11,721	199	1,215	10,444	658	15,854	12,588	12,548	3,306	(627)
	2014	12,047	147	1,152	27,404	922	30,776	13,083	13,121	17,655	(928)

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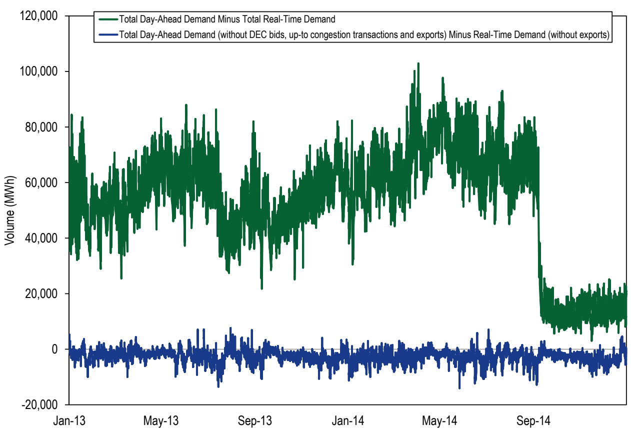
Figure 3-20 shows the difference between the day-ahead and real-time average daily demand in 2013 and 2014. The sharp decrease in UTC MW in September, which resulted in a corresponding decrease in day-ahead demand, was a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[44]

Figure 3-20 Difference between day-ahead and real-time demand (Average daily volumes): 2013 and 2014



Supply and Demand: Load and Spot Market

Real-Time Load and Spot Market

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

Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In addition to directly serving load, load serving entities can also transfer their responsibility to serve load to other parties through eSchedules transactions referred to as wholesale load responsibility (WLR) or retail load responsibility (RLR) transactions. When the responsibility to serve load is transferred via a bilateral contract, the entity to which the responsibility is transferred becomes the load serving entity. Supply from its own generation (self-supply) means that the parent company is generating power from plants that it owns in order to meet demand. Supply from bilateral purchases means that the parent company is purchasing power under bilateral contracts from a non-affiliated company at the same time that it is meeting load. Supply from spot market purchases means that the parent company is generating less power from owned plants and/or purchasing less power under bilateral contracts than required to meet load at a defined time and, therefore, is purchasing the required balance from the spot market.

The PJM system's reliance on self-supply, bilateral contracts and spot purchases to meet real-time load is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Real-Time Energy Market for each hour. Table 3-19 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. In 2014, 10.6 percent of real-time load was supplied by bilateral contracts, 26.7 percent by spot market purchase and 62.7 percent by self-supply. Compared with 2013, reliance on bilateral contracts decreased 0.0 percentage points, reliance on spot supply increased by 1.7 percentage points and reliance on self-supply decreased by 1.7 percentage points.

44 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 3-19 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2013 and 2014

	2013			2014			Difference in Percent 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%	11.5%	25.1%	63.4%	0.4%	(3.2%)	2.8%
Nov	10.6%	27.2%	62.2%	11.8%	24.9%	63.4%	1.2%	(2.3%)	1.1%
Dec	11.3%	27.1%	61.7%	12.9%	23.4%	63.7%	1.7%	(3.6%)	2.0%
Annual	10.6%	25.0%	64.4%	10.6%	26.7%	62.7%	0.0%	1.7%	(1.7%)

Day-Ahead Load and Spot Market

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

Table 3-20 Monthly average percentage of day-ahead self-supply demand, bilateral supply demand, and spot-supply demand based on parent companies: 2013 and 2014

	2013			2014			Difference in Percent 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%	9.5%	24.4%	24.4%	(0.2%)	(4.5%)	(4.5%)
Nov	9.3%	29.1%	61.7%	10.7%	24.2%	24.2%	1.4%	(4.9%)	(4.9%)
Dec	9.9%	25.6%	64.5%	11.3%	23.0%	23.0%	1.4%	(4.5%)	(4.5%)
Annual	8.0%	24.5%	67.5%	9.4%	26.1%	64.4%	1.0%	2.4%	(3.4%)

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. In 2014, 9.4 percent of day-ahead demand was supplied by bilateral contracts, 26.1 percent by spot market purchases, and 64.4 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.

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

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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 2014, the percentage of hours in which black start and reactive service units were economic increased compared to 2013 and the percentage of hours they were committed as offer capped decreased as a result.

Table 3-21 Offer-capping statistics – Energy only: 2010 to 2014

	Real Time		Day Ahead	
Year	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2010	1.2%	0.4%	0.2%	0.1%
2011	0.6%	0.2%	0.0%	0.0%
2012	0.8%	0.4%	0.1%	0.1%
2013	0.4%	0.2%	0.1%	0.0%
2014	0.5%	0.2%	0.2%	0.1%

Table 3-22 Offer-capping statistics for energy and reliability: 2010 to 2014

	Real Time		Day Ahead	
Year	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2010	1.2%	0.4%	0.2%	0.1%
2011	0.7%	0.2%	0.0%	0.0%
2012	1.7%	1.0%	0.9%	0.5%
2013	2.9%	2.4%	3.2%	2.1%
2014	0.8%	0.5%	0.6%	0.4%

Table 3-23 Real-time offer-capped unit statistics: 2013 and 2014

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:		Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2014	1	0	0	0	0	0
	2013	0	0	0	0	0	0
80% and < 90%	2014	2	0	0	3	0	0
	2013	0	0	0	1	1	3
75% and < 80%	2014	1	0	0	0	1	0
	2013	0	0	0	0	1	2
70% and < 75%	2014	0	0	0	0	0	0
	2013	0	0	1	0	0	3
60% and < 70%	2014	0	0	0	1	7	5
	2013	0	0	0	0	0	4
50% and < 60%	2014	0	0	0	0	3	6
	2013	0	0	0	0	0	9
25% and < 50%	2014	0	3	1	1	10	45
	2013	0	3	3	1	7	44
10% and < 25%	2014	0	1	4	1	8	56
	2013	2	0	0	4	3	46

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 three months of 2014 because higher LMPs resulted in the increased economic dispatch of black start and reactive service resources. PJM also created closed loop interfaces to, in some cases, model reactive constraints in price formation, which also contributed to the reduction in units offer capped for reliability outside of the energy market in 2014.

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

Table 3-23 shows that one unit was offer capped for 90 percent or more of its run hours in 2014 compared to none in 2013.

Offer Capping for Local Market Power

In 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 100 or more hours or resulting from an interface constraint. The AECO, DEOK, DAY, EKPC, Met-Ed, JCPL, and RECO control zones did not have constraints binding for 100 or more hours in 2014. Table 3-24 shows that AEP, AP, BGE, ComEd, Dominion, DPL, PECO, PENELEC, Pepco, PPL, and PSEG were the control zones experienced congestion resulting from one or more constraints binding for 100 or more hours or resulting from an interface constraint that was binding for one or more hours in every year in 2009 through 2014. In 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 resulting from one or more constraints binding for 100 or more hours or from an interface constraint: 2009 through 2014

	2009	2010	2011	2012	2013	2014
AECO	149	163	234	NA	NA	NA
AEP	906	580	2,012	NA	928	1,283
AP	1,297	3,173	1,718	NA	NA	170
ATSI	140	NA	NA	208	68	481
BGE	127	274	368	1,501	1,040	4,416
ComEd	687	1,676	788	1,727	2,920	1,928
DEOK	NA	NA	NA	109	NA	NA
DLCO	156	393	NA	209	NA	223
Dominion	456	889	1,495	559	972	102
DPL	NA	111	NA	382	597	350
Met-Ed	NA	168	NA	NA	NA	NA
PECO	247	NA	276	NA	390	1,744
PENELEC	NA	NA	NA	NA	NA	2,147
Pepco	149	NA	NA	143	200	41
PPL	176	117	40	146	42	148
PSEG	303	515	946	259	1,993	2,132

Table 3-25 Three pivotal supplier test details for interface constraints: 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	383	387	12	1	11
AEP - DOM	Peak	308	261	8	0	8
	Off Peak	323	211	7	0	7
AP South	Peak	398	463	9	0	9
	Off Peak	426	518	9	0	9
BC/PEPCO	Peak	582	585	7	0	6
	Off Peak	482	468	6	0	6
Bedington - Black Oak	Peak	157	187	13	3	10
	Off Peak	196	159	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	747	787	15	4	11
	Off Peak	765	851	13	2	11

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 in 2014.[45] 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.

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.

45 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: 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	919	82	9%	2	0%	2%
AEP - DOM	Peak	117	6	5%	1	1%	17%
	Off Peak	238	29	12%	0	0%	0%
AP South	Peak	4611	189	4%	2	0%	1%
	Off Peak	3578	177	5%	5	0%	3%
BC/PEPCO	Peak	246	26	11%	0	0%	0%
	Off Peak	112	8	7%	0	0%	0%
Bedington - Black Oak	Peak	1266	106	8%	13	1%	12%
	Off Peak	377	39	10%	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	1691	150	9%	10	1%	7%
	Off Peak	792	35	4%	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.[46] 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 Average, real-time marginal unit markup index (By offer price category): 2013 and 2014

	2013			2014		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.44	($3.21)	21.0%	(0.10)	($2.43)	16.9%
$25 to $50	(0.01)	($1.08)	62.9%	(0.02)	($1.04)	58.8%
$50 to $75	0.02	$0.71	8.1%	0.06	$2.52	6.7%
$75 to $100	0.09	$7.53	1.5%	0.12	$9.46	1.9%
$100 to $125	0.13	$13.47	0.7%	0.04	$4.29	3.4%
$125 to $150	0.03	$4.40	1.6%	0.11	$13.69	1.0%
>= $150	0.03	$7.53	4.3%	0.05	$13.25	11.3%

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 2014, 75.6 percent of marginal units had average dollar markups less than zero and 75.6 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 2014 was $ 922.26 while the highest markup in 2013 was $355.89. The unit with the highest markup in 2014 was marginal for at least one interval on January 6, 2014. The unit with highest markup in 2013 was marginal for at least one interval on July 21, 2013.

46 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.

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Day-Ahead Markup

Table 3-28 shows the average markup index of marginal units in the Day-Ahead Energy Market, by offer price category. In 2014, 87.8 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.03. The data show that some marginal units did have substantial markups. The average markup index increased significantly, for example, from 0.00 in 2013, to 0.16 in 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 2013. However, in 2014, there were 595 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): 2013 and 2014

	2013			2014		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.07)	($1.78)	19.2%	(0.08)	($2.31)	16.5%
$25 to $50	(0.04)	($2.40)	75.2%	(0.02)	($0.90)	70.5%
$50 to $75	0.00	($2.46)	4.6%	0.05	$2.17	7.5%
$75 to $100	0.08	$6.63	0.4%	0.09	$6.63	1.1%
$100 to $125	0.00	$0.00	0.1%	0.16	$17.04	0.8%
$125 to $150	0.00	$0.00	0.0%	0.02	($2.02)	0.7%
>= $150	0.75	$118.80	0.0%	0.04	$8.53	2.7%

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 FMU adder was filed with FERC in 2005, and approved effective February 2006.[47] 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 maintains the ability of certain generating units to qualify for FMU adders but limits 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.[48] On October 31, 2014, the Commission conditionally approved the filing and the new rule became effective November 1, 2014.[49,50]

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 10 percent of their cost-based offer or $30 per

47 110 FERC ¶ 61,053 (2005).

48 See PJM Interconnection, L.L.C Docket No. EL14-95-000 (August 26, 2014).

49 The Commission directed PJM to amend the provisions of the PJM tariff to include the words "greater of" when determining whether the Offer Price Adder will be either the incremental cost plus 10 percent, of the specific incremental adder.

50 149 FERC ¶ 61,091 (2014).

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MWh. Units capped for 80 percent or more of their run hours are entitled to an adder of either 10 percent of their cost-based offer or $40 per MWh. These categories are designated Tier 1, Tier 2 and Tier 3.

In addition to being offer capped for the designated percent of run hours, in order to qualify for the FMU adder, a generating unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis, divided by the unit's MW of installed capacity (in $/MW-year) must be less than its accepted unit specific Avoidable Cost Rate (in $/MW-year) (excluding APIR and ARPIR), or its default Avoidable Cost Rate (in $/MW-year) if no unit-specific Avoidable Cost Rate is accepted for the BRAs for the Delivery Years included in the rolling 12-month period, determined pursuant to Sections 6.7 and 6.8 of Attachment DD of the Tariff. (The relevant Avoidable Cost Rate is the weighted average of the Avoidable Cost Rates for each Delivery Year included in the rolling 12-month period, weighted by month.) No portion of the unit may be included in a FRR Capacity Plan or be receiving compensation under Part V of the PJM Tariff and the unit must be internal to the PJM Region and subject only to PJM dispatch.[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.[52] 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.

The new rules for determining the qualification of a unit as a FMU or AU became effective November 1, 2014. 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.[53] The effects of the new rules were first observed in units eligible for an FMU or AU adder in December, 2014, where the number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to 10 in December 2014 (See Table 3-30).

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 2014. Of the 112 units eligible in at least one month during 2014, 4 units (3.5 percent) were FMUs or AUs for all months, and 21 units (18.8 percent) qualified in only one month of 2014.

Table 3-29 Frequently mitigated units and associated units by total months eligible: 2013 and 2014

Months Adder-Eligible	FMU & AU Count	
	2013	2014
1	10	21
2	22	9
3	14	0
4	10	3
5	5	5
6	8	15
7	7	1
8	3	6
9	1	8
10	2	5
11	8	35
12	22	4
Total	112	112

Figure 3-21 shows the number of months FMUs and AUs were eligible for any adder (Tier 1, Tier 2 or Tier 3) since the inception of FMUs effective February 1, 2006. From February 1, 2006, through December 31, 2014, there were 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 months. Two units qualified in 103 of the 108 possible months, and 87 of the 351 units (24.8 percent) qualified for an adder in more than half of the possible months.

51 PJM. OA, Schedule 1 § 6.4.2.

52 An associated unit (AU) must belong to the same design class (where a design class includes generation that is the same size and utilizes the same technology, without regard to manufacturer) and uses the identical primary fuel as the FMU.

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

Figure 3-21 Frequently mitigated units and associated units total months eligible: February, 2006 through December, 2014

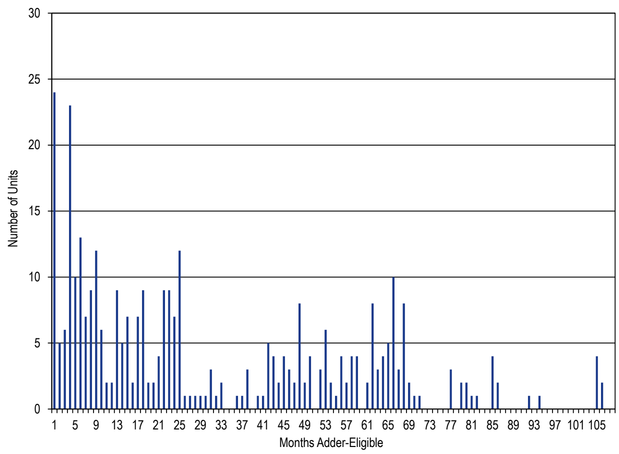

Table 3-30 shows, by month, the number of FMUs and AUs in 2013 and 2014. For example, in January 2014, there were 7 FMUs and AUs in Tier 1, 27 FMUs and AUs in Tier 2, and 49 FMUs and AUs in Tier 3.

Table 3-30 Number of frequently mitigated units and associated units (By month): 2013 and 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	16	11	19	46
November	10	29	49	88	25	15	15	55
December	10	31	40	81	10	0	0	10

Figure 3-22 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 November of 2014. The reduction in the total number of units qualifying for an FMU or AU adder in December 2014 was the result of the revised rules for FMUs.

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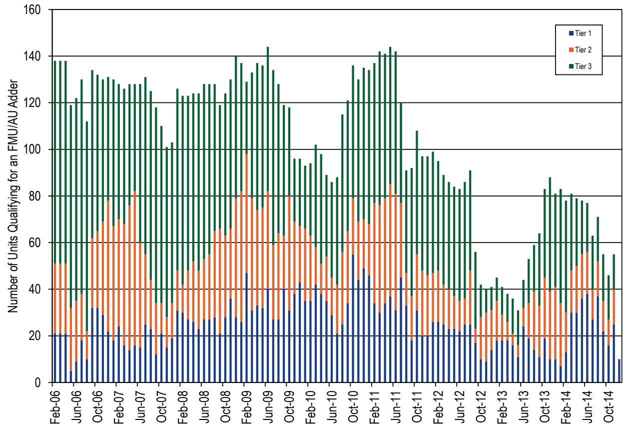
Figure 3-22 Frequently mitigated units and associated units (By month): February, 2006 through September, 2014



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

Figure 3-23 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 2014.

Figure 3-23 PJM day-ahead aggregate supply curves: 2014 example day

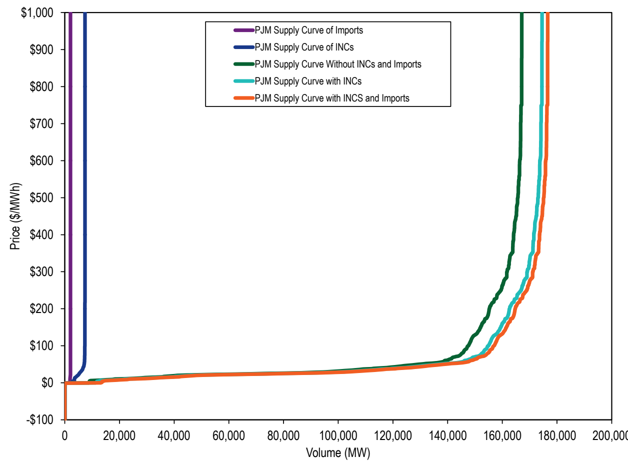


Table 3-31 shows the average hourly number of increment offers and decrement bids and the average hourly MW in 2013 and 2014. In 2014, the average hourly submitted and cleared increment offer MW decreased 18.2 and 31.9 percent, and the average hourly submitted and cleared decrement bid MW increased 2.1 and decreased 8.4 percent, compared to 2013.

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

Table 3-31 Hourly average number of cleared and submitted INCs, DECs by month2013 and 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	2,961	3,889	66	179	6,744	9,452	97	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	Oct	3,477	5,826	91	470	6,806	9,991	136	510
2014	Nov	4,210	7,151	134	553	7,193	11,028	166	637
2014	Dec	3,992	7,021	102	525	7,210	10,260	139	490
2014	Annual	3,494	5,279	78	310	6,596	9,278	125	393

In 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.[55] Table 3-32 shows the average hourly number of up-to congestion transactions and the average hourly MW for 2013 and 2014. In 2014, the average hourly up-to congestion submitted MW decreased 5.0 percent and cleared MW decreased 4.0 percent, compared to 2013, as a result of the decreases after September 8.

55 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 3-32 Hourly average of cleared and submitted up-to congestion bids by month: 2013 and 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	66,003	243,469	3,527	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	Oct	9,298	30,502	512	1,289
2014	Nov	11,890	36,600	661	1,633
2014	Dec	12,952	37,177	770	1,770
2014	Annual	49,511	166,537	2,269	6,315

Table 3-33 Hourly average number of cleared and submitted import and export transactions by month: 2013 and 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	Oct	1,714	1,721	11	11	3,506	3,525	20	21
2014	Nov	2,087	2,097	13	13	3,491	3,528	21	21
2014	Dec	2,373	2,498	12	13	3,939	3,959	21	22
2014	Annual	2,221	2,276	12	13	3,740	3,823	22	22

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Table 3-33 shows the average hourly number of import and export transactions and the average hourly MW for 2013 and 2014. In 2014, the average hourly submitted and cleared import transaction MW decreased 3.5 and 2.3 percent, and the average hourly submitted and cleared export transaction MW increased 15.5 and 14.3 percent, compared to 2013.

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

Table 3-34 Type of day-ahead marginal units: 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%
Oct	12.4%	0.1%	63.8%	14.5%	9.2%	0.0%
Nov	10.6%	0.2%	64.5%	14.5%	10.1%	0.0%
Dec	12.7%	0.2%	67.2%	12.4%	7.6%	0.0%
Annual	3.4%	0.1%	91.0%	3.3%	2.3%	0.0%

Figure 3-24 shows the monthly volume of bid and cleared INC, DEC and up-to congestion bids by month for the period from 2005 through 2014. Figure 3-25 shows the daily volume of bid and cleared INC, DEC and up-to congestion bids for the period for 2013 through 2014 in order to show the drop off in UTC volumes compared to volumes in the last two years.

Figure 3-24 Monthly bid and cleared INCs, DECs, and UTCs (MW): January 2005 through 2014

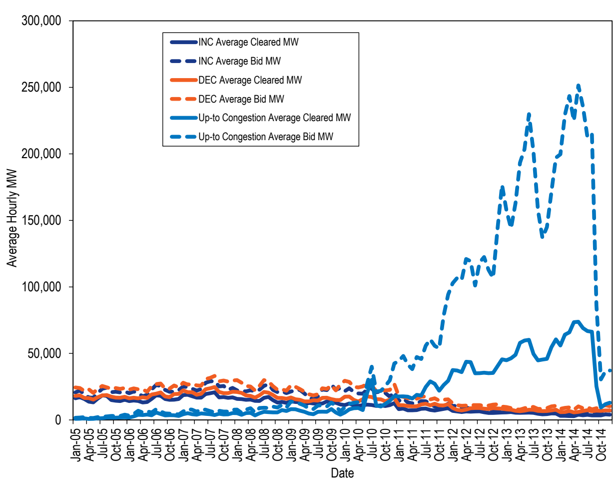
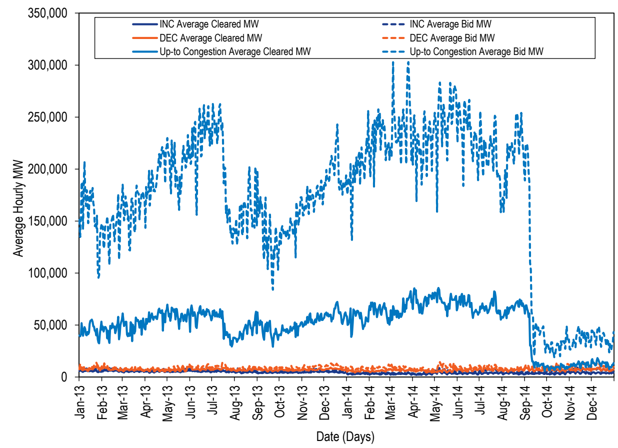


Figure 3-25 Daily bid and cleared INCs, DECs, and UTCs (MW): 2013 and 2014



In order to evaluate the ownership of virtual bids, the MMU categorizes all participants making virtual bids in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 3-35 shows, for 2013 and 2014, the total increment offers and decrement bids by whether the parent organization is financial or physical.

The top five companies with cleared up-to congestion transactions are financial and account for 43.8 percent of all the cleared up-to congestion MW in PJM in 2014, which is lower than the 57.1 percent in 2013. The cleared up-to congestion MW from financial companies increased 28.8 percent in 2014 compared to 2013. At the same time, the cleared up-to congestion MW from physical companies decreased by 33.3 percent decrease in 2014 compared to 2013.

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

	2013		2014	
Category	Total Up-to Congestion MW	Percent	Total Up-to Congestion MW	Percent
Financial	432,126,914	95.6%	418,069,242	96.4%
Physical	19,875,032	4.4%	15,649,759	3.6%
Total	452,001,946	100.0%	433,719,001	100.0%

Table 3-36 shows, for 2013 and 2014, the total up-to congestion transactions by the type of parent organization.

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

	2013		2014	
Category	Total Up-to Congestion MW	Percent	Total Up-to Congestion MW	Percent
Financial	432,126,914	95.6%	420,313,334	96.9%
Physical	19,875,032	4.4%	13,254,209	3.1%
Total	452,001,946	100.0%	433,567,543	100.0%

Table 3-37 shows, for 2013 and 2014, the total import and export transactions by whether the parent organization is financial or physical.

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

	2013		2014	
Category	Total Import and Export MW	Percent	Total Import and Export MW	Percent
Financial	20,687,175	42.6%	20,974,916	39.2%
Physical	27,894,650	57.4%	32,494,237	60.8%
Total	48,581,824	100.0%	53,469,153	100.0%

Table 3-38 shows increment offers and decrement bids bid by top ten locations for 2013 and 2014.

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

2013					2014				
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	23,707,340	26,374,640	50,081,980	WESTERN HUB	HUB	14,144,703	15,893,094	30,037,797
N ILLINOIS HUB	HUB	2,505,451	5,216,166	7,721,617	MISO	INTERFACE	398,020	7,059,365	7,457,385
AEP-DAYTON HUB	HUB	3,518,673	3,519,770	7,038,444	PPL	ZONE	267,611	6,406,957	6,674,568
SOUTHIMP	INTERFACE	6,790,504	0	6,790,504	SOUTHIMP	INTERFACE	5,941,022	0	5,941,022
IMO	INTERFACE	6,024,671	50,665	6,075,336	PECO	ZONE	353,796	5,389,912	5,743,708
PPL	ZONE	93,838	5,351,384	5,445,221	AEP-DAYTON HUB	HUB	2,299,256	2,368,248	4,667,503
MISO	INTERFACE	372,646	3,911,598	4,284,244	IMO	INTERFACE	4,236,242	174,918	4,411,159
PECO	ZONE	118,146	3,845,095	3,963,241	N ILLINOIS HUB	HUB	1,044,461	2,696,413	3,740,873
BGE	ZONE	34,983	2,187,199	2,222,181	BGE	ZONE	25,651	2,999,624	3,025,276
DOMINION HUB	HUB	347,155	1,582,833	1,929,987	NYIS	INTERFACE	1,081,753	488,366	1,570,119
Top ten total		43,513,406	52,039,349	95,552,755			29,792,514	43,476,896	73,269,410
PJM total		56,515,678	79,611,882	136,127,559			46,246,816	81,275,169	127,521,984
Top ten total as percent of PJM total		77.0%	65.4%	70.2%			64.4%	53.5%	57.5%

Table 3-39 shows up-to congestion transactions by import bids for the top ten locations for 2013 and 2014.[56]

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

2013				
Imports				
Source	Source Type	Sink	Sink Type	MW
OVEC	INTERFACE	DEOK	ZONE	1,277,685
OVEC	INTERFACE	STUART 1	AGGREGATE	1,033,271
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	971,443
NYIS	INTERFACE	HUDSON BC	AGGREGATE	894,530
NORTHWEST	INTERFACE	ZION 1	AGGREGATE	733,906
NORTHWEST	INTERFACE	BYRON 1	AGGREGATE	576,253
OVEC	INTERFACE	BECKJORD 6	AGGREGATE	569,729
OVEC	INTERFACE	SPORN 2	AGGREGATE	524,883
IMO	INTERFACE	WESTERN HUB	HUB	489,032
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	482,986
Top ten total				7,553,718
PJM total				40,902,161
Top ten total as percent of PJM total				18.5%
2014				
Imports				
Source	Source Type	Sink	Sink Type	MW
HUDSONTP	INTERFACE	LEONIA 230 T-2	AGGREGATE	979,669
SOUTHEAST	INTERFACE	EDANVILL T1	AGGREGATE	759,991
MISO	INTERFACE	COOK	EHVAGG	666,261
OVEC	INTERFACE	BIG SANDY CT1	AGGREGATE	603,745
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	571,373
MISO	INTERFACE	AEP-DAYTON HUB	HUB	462,719
NEPTUNE	INTERFACE	SOUTHRIV 230	AGGREGATE	436,574
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	428,397
OVEC	INTERFACE	AEP-DAYTON HUB	HUB	402,375
HUDSONTP	INTERFACE	LEONIA 230 T-1	AGGREGATE	383,260
Top ten total				5,694,366
PJM total				29,282,620
Top ten total as percent of PJM total				19.4%

56 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 3-40 shows up-to congestion transactions by export bids for the top ten locations for 2013 and 2014.

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

		2013		
		Exports		
Source	Source Type	Sink	Sink Type	MW
JEFFERSON	EHVAGG	OVEC	INTERFACE	2,337,713
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	1,489,113
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	1,347,573
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	1,233,366
TANNERS CRK 4	AGGREGATE	OVEC	INTERFACE	1,157,724
ROCKPORT	EHVAGG	OVEC	INTERFACE	1,007,610
F387 CHICAGOH	AGGREGATE	NIPSCO	INTERFACE	828,452
GAVIN	EHVAGG	OVEC	INTERFACE	706,465
21 KINCA ATR24304	AGGREGATE	OVEC	INTERFACE	688,745
EAST BEND 2	AGGREGATE	OVEC	INTERFACE	661,555
Top ten total				11,458,315
PJM total				49,738,703
Top ten total as percent of PJM total				23.0%
		2014		
		Exports		
Source	Source Type	Sink	Sink Type	MW
JEFFERSON	EHVAGG	OVEC	INTERFACE	2,073,052
TANNERS CRK 4	AGGREGATE	SOUTHWEST	INTERFACE	1,782,780
TANNERS CRK 4	AGGREGATE	OVEC	INTERFACE	809,364
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	693,816
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	607,054
JEFFERSON	EHVAGG	SOUTHWEST	INTERFACE	606,723
ROCKPORT	EHVAGG	OVEC	INTERFACE	564,629
EAST BEND 2	AGGREGATE	SOUTHWEST	INTERFACE	427,156
UNIV PARK 1-6	AGGREGATE	NIPSCO	INTERFACE	426,011
BECKJORD 6	AGGREGATE	OVEC	INTERFACE	418,718
Top ten total				8,409,302
PJM total				30,285,649
Top ten total as percent of PJM total				27.8%

Table 3-41 shows up-to congestion transactions by wheel bids for the top ten locations for 2013 and 2014.

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

		2013		
		Wheels		
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	766,264
NORTHWEST	INTERFACE	MISO	INTERFACE	677,453
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	479,746
IMO	INTERFACE	NYIS	INTERFACE	330,340
MISO	INTERFACE	NIPSCO	INTERFACE	303,181
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	143,047
OVEC	INTERFACE	IMO	INTERFACE	131,155
MISO	INTERFACE	SOUTHEXP	INTERFACE	118,693
LINDENVFT	INTERFACE	NYIS	INTERFACE	86,796
MISO	INTERFACE	OVEC	INTERFACE	83,065
Top ten total				3,119,740
PJM total				4,177,320
Top ten total as percent of PJM total				74.7%
		2014		
		Wheels		
Source	Source Type	Sink	Sink Type	MW
NORTHWEST	INTERFACE	MISO	INTERFACE	775,527
OVEC	INTERFACE	SOUTHEXP	INTERFACE	344,298
MISO	INTERFACE	NORTHWEST	INTERFACE	334,888
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	255,763
MISO	INTERFACE	NIPSCO	INTERFACE	128,693
OVEC	INTERFACE	SOUTHWEST	INTERFACE	120,854
MISO	INTERFACE	SOUTHEXP	INTERFACE	97,877
NYIS	INTERFACE	IMO	INTERFACE	97,249
IMO	INTERFACE	NYIS	INTERFACE	91,942
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	89,794
Top ten total				2,336,885
PJM total				2,984,112
Top ten total as percent of PJM total				78.3%

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. The top ten internal up-to congestion transaction locations were 9.8 percent of the PJM total internal up-to congestion transactions in 2014.

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

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

2013				
Internal				
Source	Source Type	Sink	Sink Type	MW
ATSI GEN HUB	HUB	ATSI	ZONE	5,675,792
SUNBURY 1-3	AGGREGATE	CITIZENS	AGGREGATE	4,405,866
MT STORM	EHVAGG	GREENLAND GAP	EHVAGG	3,910,366
FE GEN	AGGREGATE	ATSI	ZONE	2,980,966
WYOMING	EHVAGG	BROADFORD	EHVAGG	2,939,931
AEP-DAYTON HUB	HUB	WESTERN HUB	HUB	2,142,829
SUNBURY 1-3	AGGREGATE	FOSTER WHEELER	AGGREGATE	1,917,015
WHITPAIN	EHVAGG	ELROY	EHVAGG	1,868,461
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	1,559,654
CORDOVA	AGGREGATE	QUAD CITIES 2	AGGREGATE	1,522,733
Top ten total				28,923,614
PJM total				357,183,762
Top ten total as percent of PJM total				8.1%
2014				
Internal				
Source	Source Type	Sink	Sink Type	MW
MOUNTAINEER	EHVAGG	GAVIN	EHVAGG	6,627,189
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	5,207,776
MOUNTAINEER	EHVAGG	FLATLICK	EHVAGG	4,297,331
ATSI GEN HUB	HUB	ATSI	ZONE	4,114,584
VERNON BK 4	AGGREGATE	AEC - JC	AGGREGATE	3,733,527
FE GEN	AGGREGATE	ATSI	ZONE	3,357,260
JEFFERSON	EHVAGG	COOK	EHVAGG	2,548,989
DUMONT	EHVAGG	COOK	EHVAGG	2,466,575
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	2,147,264
TANNERS CRK 4	AGGREGATE	STUART DIESEL	AGGREGATE	1,813,835
Top ten total				36,314,330
PJM total				371,166,620
Top ten total as percent of PJM total				9.8%

Table 3-43 shows the number of source-sink pairs that were offered and cleared monthly in January of 2012 through 2014. The annual row in Table 3-43 is the average hourly number of offered and cleared source-sink pairs for the year for the average columns and the maximum hourly number of offered and cleared source-sink pairs for the year for the maximum columns. The increase in average offered and cleared source-sink pairs beginning in November and December of 2012 and continuing through the first eight 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. 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.[57]

Table 3-43 Number of PJM offered and cleared source and sink pairs: 2012 through 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	Oct	2,871	4,092	1,972	2,506
2014	Nov	2,463	3,988	1,812	3,163
2014	Dec	2,803	3,672	2,197	2,786
2014	Annual	8,109	14,745	5,690	10,253

57 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 3-44 and Figure 3-26 show total cleared up-to congestion transactions by type for 2013 and 2014. Internal up-to congestion transactions in 2014 were 85.6 percent of all up-to congestion transactions compared to 79.0 percent in 2013.

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

	2013				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	7,553,718	11,458,315	3,119,740	28,923,614	51,055,387
PJM total (MW)	40,902,161	49,738,703	4,177,320	357,183,762	452,001,946
Top ten total as percent of PJM total	18.5%	23.0%	74.7%	8.1%	11.3%
PJM total as percent of all up-to congestion transactions	9.0%	11.0%	0.9%	79.0%	100.0%
	2014				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	5,694,366	8,409,302	2,336,885	36,314,330	52,754,883
PJM total (MW)	29,282,620	30,285,649	2,984,112	371,166,620	433,719,001
Top ten total as percent of PJM total	19.4%	27.8%	78.3%	9.8%	12.2%
PJM total as percent of all up-to congestion transactions	6.8%	7.0%	0.7%	85.6%	100.0%

Figure 3-26 shows the initial increase and continued increase in 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.[58] Figure 3-27 shows the daily cleared up-to congestion MW by transaction type for the period from January 2013 through December 2014 in order to show the drop off in UTC volumes compared to volumes in the last two years.

Figure 3-26 PJM monthly cleared up-to congestion transactions by type (MW): 2005 through 2014

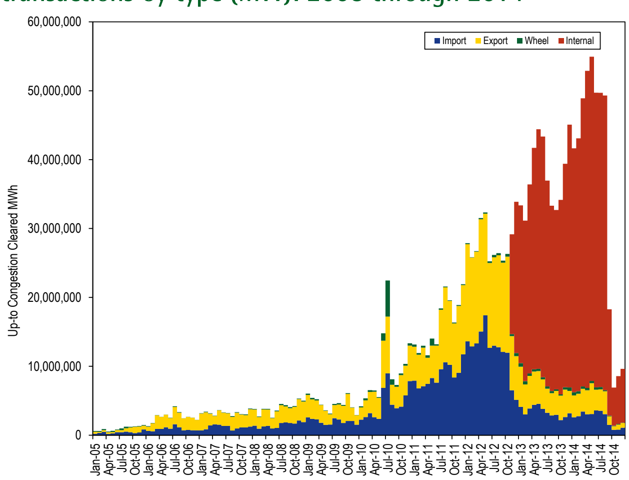
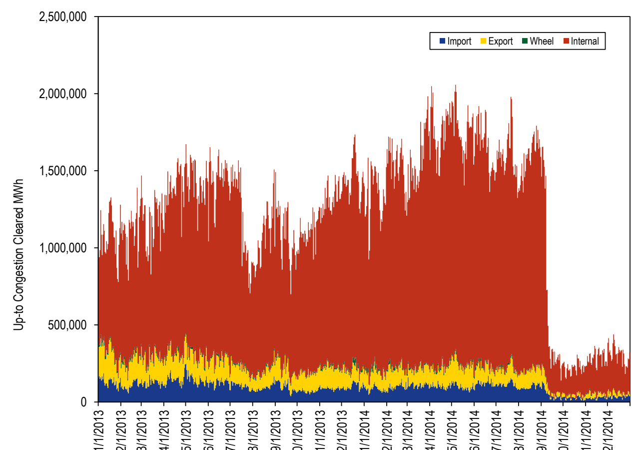


Figure 3-27 PJM daily cleared up-to congestion transaction by type (MW): 2013 through 2014



Generator Offers

Generator offers are categorized as dispatchable (Table 3-45) or self scheduled (Table 3-46).[59] 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

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).

59 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.

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3-45 and Table 3-46 do not include units that did not indicate their offer status and units that were offered as available to run only during emergency events. The MW offered beyond the economic range of a unit, i.e. MW range between the specified economic maximum and emergency maximum, are categorized as emergency MW. The emergency MW are included in both tables.

Table 3-45 shows the proportion of MW offers by dispatchable units, by unit type and by offer price range, for 2014. For example, 66.9 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, 80.3 percent of all CC MW offers were dispatchable, including the 7.6 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, 42.0 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 2014, 56.1 percent were offered as available for economic dispatch.

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

	Dispatchable (Range)							
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	0.1%	66.9%	3.2%	1.4%	0.4%	0.7%	7.6%	80.3%
CT	0.1%	54.1%	24.8%	6.2%	1.8%	0.8%	11.6%	99.3%
Diesel	3.0%	15.5%	24.7%	8.7%	1.9%	1.6%	15.6%	71.0%
Run of River	0.0%	10.9%	0.0%	0.0%	0.0%	0.0%	0.1%	11.0%
Nuclear	9.1%	35.9%	0.0%	0.0%	0.0%	0.0%	12.5%	57.4%
Pumped Storage	0.1%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%
Solar	0.7%	6.6%	0.0%	0.0%	0.0%	0.0%	0.1%	7.4%
Steam	0.0%	46.0%	2.0%	0.3%	0.1%	0.2%	3.4%	52.0%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	41.5%	8.1%	0.0%	0.0%	0.0%	0.0%	0.6%	50.2%
All Dispatchable Offers	0.9%	42.0%	5.9%	1.5%	0.4%	0.3%	5.1%	56.1%

Table 3-46 shows the proportion of MW offers by unit type that were self scheduled to generate fixed output and by unit type and price range for self-scheduled and dispatchable units, for 2014. For example, 16.7 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, 19.7 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 1.5 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 20.8 percent of all offers and self-scheduled and dispatchable units accounted for 19.4 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 2014, 22.9 percent were offered as self scheduled and 21.0 percent were offered as self scheduled and dispatchable.

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Table 3-46 Distribution of MW for self scheduled offer prices: 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	0.9%	0.3%	0.2%	16.7%	0.3%	0.1%	0.0%	0.0%	1.2%	19.7%
CT	0.4%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%
Diesel	25.4%	3.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	29.0%
Hydro	83.9%	4.7%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.1%	89.0%
Nuclear	21.2%	10.1%	2.9%	1.6%	0.0%	0.0%	0.0%	0.0%	6.7%	42.6%
Pumped Storage	59.7%	15.2%	5.2%	14.0%	0.0%	0.0%	0.0%	1.7%	3.9%	99.6%
Solar	68.3%	23.6%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	92.6%
Steam	4.7%	1.3%	0.2%	38.9%	0.1%	0.0%	0.0%	0.0%	2.8%	48.0%
Transaction	78.5%	21.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	5.2%	4.2%	32.4%	2.7%	0.0%	0.0%	0.0%	0.0%	5.3%	49.8%
All Self-Scheduled Offers	20.8%	2.1%	0.7%	18.6%	0.1%	0.0%	0.0%	0.0%	1.6%	43.9%

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.[60]

The price impact of markup must be interpreted carefully. The markup calculation is not based on a full redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at marginal cost. Thus the results do not reflect a counterfactual market outcome based on the assumption that all units made all offers at marginal cost. It is important to note that a full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on marginal cost and actual dispatch. It is possible that the unit-specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

The MMU calculated an explicit measure of the impact of marginal unit markups on LMP. The markup impact includes the impact of the identified markup conduct on a unit by unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the Energy Market.

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

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Real-Time Markup

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

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

Table 3-47 shows the average unit markup component of LMP for marginal units, by unit type and primary fuel. The markup component of LMP is a measure of the impact of the markups of marginal units shown in Table 3-47 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 3-27.

Table 3-47 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: 2013 and 2014[61]

		2013		2014	
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	($0.64)	$0.87	$0.32	$1.75
Gas	CC	$0.03	$0.03	$0.83	$0.83
Gas	CT	$0.13	$0.13	$0.27	$0.27
Gas	Diesel	$0.06	$0.06	$0.02	$0.02
Gas	Steam	$0.00	$0.00	($0.01)	($0.01)
Municipal Waste	Steam	($0.01)	($0.01)	$0.15	$0.15
Oil	CC	$0.01	$0.01	$0.09	$0.09
Oil	CT	$0.02	$0.02	$0.09	$0.09
Oil	Diesel	$0.00	$0.00	$0.07	$0.07
Oil	Steam	$0.06	$0.06	$0.03	$0.03
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	$0.03	$0.03
Total		($0.35)	$1.16	$1.88	$3.32

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.[62]

In order to accurately assess the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach, markup is the difference between the active offer of the marginal unit and the cost offer. In the second approach, the 10 percent markup is removed from the cost offers of coal units because coal units do not face the same cost uncertainty as gas-fired CTs. The adjusted markup is calculated as the difference between the active offer and the cost offer excluding the 10 percent adder. The unadjusted markup is calculated as the difference between the active offer and the cost offer including the 10 percent adder in the cost offer.

Table 3-47 shows the mark-up component of the load-weighted LMP by fuel type and unit type using unadjusted and adjusted offers. The adjusted markup component of LMP increased from $1.16 in 2013 to $3.32 in 2014. The adjusted markup contribution of coal units in 2014 was $1.75. The adjusted mark-up component of all gas-fired units in 2014 was $1.11. Coal units accounted for 40.8 percent of the increased markup component of LMP in

61 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.

62 See PJM. "Manual 15: Cost Development Guidelines," Revision: 25 (July 28, 2014).

2014 while gas units accounted for 40.9 percent. The markup component of wind units was 0.03. If a price-based offer is negative but less negative than a cost-based offer, the markup is positive. In 2014, among the wind units that were marginal, 2.55 percent had positive offer prices.

Markup Component of Real-Time Price

Table 3-48 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on-peak and off-peak prices. Table 3-49 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on-peak and off-peak prices. In 2014, when using unadjusted cost offers, $1.88 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-offers, $3.32 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In 2014, the peak markup component was highest in March, $11.17 per MWh using unadjusted cost offers and $12.02 per MWh using adjusted cost offers. This corresponds to 14.72 percent and 15.83 percent of the real time load-weighted average LMP in March.

Table 3-48 Monthly markup components of real-time load-weighted LMP (Unadjusted): 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	($3.18)	($4.12)	($2.29)	$5.44	$3.91	$6.92
Feb	($1.84)	($2.95)	($0.76)	$3.02	$0.88	$5.08
Mar	$0.64	($0.90)	$2.24	$7.11	$3.24	$11.17
Apr	($1.75)	($2.88)	($0.78)	($0.43)	($2.16)	$1.07
May	$0.15	($2.92)	$2.72	$1.74	($1.27)	$4.62
Jun	$0.44	($1.07)	$1.94	$2.43	($0.08)	$4.60
Jul	$3.86	($0.21)	$7.44	($0.15)	($1.22)	$0.77
Aug	($0.81)	($1.94)	$0.15	($1.08)	($1.91)	($0.29)
Sep	($1.22)	($2.31)	($0.15)	$1.51	($0.13)	$3.01
Oct	$0.23	($0.84)	$1.13	$2.04	($0.74)	$4.34
Nov	($1.00)	($1.36)	($0.62)	$0.17	($1.12)	$1.70
Dec	($0.44)	($1.21)	$0.37	($0.19)	($1.59)	$1.13
Total	($0.35)	($1.85)	$1.07	$1.88	($0.06)	$3.71

Table 3-49 Monthly markup components of real-time load-weighted LMP (Adjusted): 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	($1.39)	($2.22)	($0.60)	$6.83	$5.48	$8.12
Feb	($0.05)	($1.04)	$0.91	$3.94	$1.97	$5.84
Mar	$2.25	$0.89	$3.66	$8.21	$4.59	$12.02
Apr	($0.48)	($1.21)	$0.15	$0.86	($0.45)	$2.00
May	$1.53	($1.16)	$3.79	$2.87	$0.09	$5.54
Jun	$1.90	$0.48	$3.31	$3.69	$1.46	$5.62
Jul	$5.15	$1.28	$8.57	$1.48	$0.35	$2.44
Aug	$0.60	($0.39)	$1.46	$0.50	($0.29)	$1.25
Sep	$0.33	($0.54)	$1.18	$3.18	$1.65	$4.59
Oct	$1.66	$0.79	$2.38	$3.71	$1.06	$5.90
Nov	$0.55	$0.31	$0.81	$1.93	$0.80	$3.25
Dec	$1.12	$0.47	$1.79	$1.65	$0.27	$2.97
Total	$1.16	($0.16)	$2.40	$3.32	$1.54	$5.00

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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 2014 and 2013 in Table 3-50 and for adjusted offers in Table 3-51. The smallest zonal all hours average markup component using unadjusted offers for 2014 was in the ComEd Zone, $0.99 per MWh, while the highest was in the Dominion Control Zone, $3.15 per MWh. The smallest zonal on peak average markup was in the ComEd Control Zone, $2.48 per MWh, while the highest was in the Dominion Control Zone, $5.39 per MWh.

Table 3-50 Average real-time zonal markup component (Unadjusted): 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	($0.23)	($1.83)	$1.32	$1.77	($0.26)	$3.71
AEP	($0.61)	($1.94)	$0.68	$1.59	($0.30)	$3.42
APS	($0.45)	($1.92)	$0.96	$1.72	($0.05)	$3.43
ATSI	($0.45)	($1.94)	$0.94	$1.25	($0.48)	$2.89
BGE	$0.09	($1.64)	$1.74	$3.14	$0.85	$5.30
ComEd	($0.56)	($1.95)	$0.70	$0.99	($0.62)	$2.48
DAY	($0.56)	($1.93)	$0.71	$1.27	($0.54)	$2.94
DEOK	($0.61)	($1.91)	$0.61	$1.27	($0.57)	$3.01
DLCO	($0.56)	($1.86)	$0.66	$1.53	($0.17)	$3.14
DPL	($0.30)	($1.82)	$1.17	$2.23	$0.25	$4.10
Dominion	($0.08)	($1.88)	$1.66	$3.15	$0.79	$5.39
EKPC	($0.08)	($1.38)	$1.23	$1.59	($0.09)	$3.26
JCPL	($0.06)	($1.63)	$1.35	$1.50	($0.33)	$3.14
Met-Ed	($0.30)	($1.85)	$1.13	$1.58	($0.12)	$3.14
PECO	($0.32)	($1.81)	$1.07	$1.83	($0.07)	$3.61
PENELEC	($0.53)	($1.83)	$0.69	$1.96	($0.11)	$3.89
PPL	($0.34)	($1.77)	$0.99	$2.02	($0.03)	$3.94
PSEG	($0.01)	($1.66)	$1.50	$2.33	$0.16	$4.31
Pepco	$0.12	($1.72)	$1.83	$2.94	$0.73	$4.97
RECO	$0.33	($1.35)	$1.77	$2.44	$0.14	$4.39

Table 3-51 Average real-time zonal markup component (Adjusted): 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	$1.26	($0.16)	$2.63	$3.04	$1.10	$4.88
AEP	$0.94	($0.22)	$2.07	$3.09	$1.37	$4.75
APS	$1.07	($0.20)	$2.30	$3.19	$1.56	$4.77
ATSI	$1.12	($0.20)	$2.35	$2.74	$1.16	$4.23
BGE	$1.61	$0.14	$3.02	$4.90	$2.78	$6.90
ComEd	$0.93	($0.31)	$2.07	$2.41	$1.01	$3.71
DAY	$1.03	($0.18)	$2.14	$2.81	$1.16	$4.33
DEOK	$0.92	($0.22)	$1.99	$2.75	$1.07	$4.34
DLCO	$0.95	($0.17)	$2.02	$3.05	$1.47	$4.53
DPL	$1.21	($0.13)	$2.49	$3.46	$1.59	$5.24
Dominion	$1.39	($0.18)	$2.91	$4.67	$2.46	$6.77
EKPC	$1.42	$0.27	$2.58	$3.06	$1.55	$4.57
JCPL	$1.37	$0.05	$2.57	$2.74	$1.03	$4.26
Met-Ed	$1.17	($0.21)	$2.43	$2.77	$1.21	$4.21
PECO	$1.15	($0.17)	$2.40	$3.05	$1.29	$4.69
PENELEC	$1.02	($0.11)	$2.08	$3.33	$1.38	$5.15
PPL	$1.15	($0.11)	$2.32	$3.23	$1.31	$5.02
PSEG	$1.45	$0.01	$2.77	$3.60	$1.52	$5.49
Pepco	$1.59	$0.01	$3.05	$4.56	$2.52	$6.44
RECO	$1.79	$0.35	$3.02	$3.79	$1.55	$5.70

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Markup by Real Time Price Levels

Table 3-52 shows the average markup component of observed prices, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM average LMP was in the identified price range.

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

	2013		2014	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.31)	77.8%	$1.67	78.0%
$25 to $50	($0.16)	20.6%	($0.24)	19.7%
$50 to $75	$0.08	1.4%	$0.20	1.6%
$75 to $100	$0.02	0.2%	$0.13	0.4%
$100 to $125	($0.01)	0.0%	$0.08	0.2%
$125 to $150	$0.02	0.0%	$0.05	0.1%
>= $150	$0.00	0.0%	$0.01	0.0%

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

	2013		2014	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$0.88	77.8%	$2.74	78.0%
$25 to $50	$0.18	20.6%	$0.11	19.7%
$50 to $75	$0.09	1.4%	$0.22	1.6%
$75 to $100	$0.02	0.2%	$0.14	0.4%
$100 to $125	($0.01)	0.0%	$0.08	0.2%
$125 to $150	$0.02	0.0%	$0.05	0.1%
>= $150	$0.00	0.0%	$0.01	0.0%

Day-Ahead Markup

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

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

		2013		2014	
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	($0.41)	$0.10	($0.27)	$0.98
Gas	CC	($0.38)	($0.38)	($0.13)	($0.13)
Gas	CT	$0.00	$0.00	$0.02	$0.02
Gas	Diesel	$0.00	$0.00	$0.00	$0.00
Gas	Steam	$0.01	$0.01	($0.03)	($0.03)
Import	Steam	$0.00	$0.00	$0.00	$0.01
Municipal Waste	Steam	$0.00	$0.00	($0.01)	($0.01)
Oil	CC	$0.00	$0.00	$0.02	$0.02
Oil	CT	$0.00	$0.00	$0.03	$0.04
Oil	Steam	$0.00	$0.00	$0.02	$0.02
Other	Steam	$0.00	$0.00	($0.01)	($0.01)
Wind	Wind	$0.00	$0.00	$0.02	$0.02
Total		($0.78)	($0.27)	($0.33)	$0.94

The markup component of the PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 3-54. INC, DEC and up-to congestion transactions have zero markups. Up-to congestion transactions were marginal for 91.0 percent of marginal resources in 2014. INCs were marginal for 2.3 percent of marginal resources and DECs were marginal for 3.3 percent of marginal resources in 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.[63] The adjusted markup of coal units is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder. Table 3-54 shows the markup component of LMP for marginal generating resources. Generating resources were marginal in only 3.4 percent of marginal resources in 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 -$0.41 in the 2013 to -$0.27 in 2014. The markup component of LMP for gas-fired CCs increased from -$0.38 in 2013 to -$0.13 in 2014.

63 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 3-55 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted offers. Table 3-56 shows the markup component of average prices and of average monthly on-peak and off-peak prices using adjusted offers. In 2014, when using adjusted cost-offers, $0.94 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In 2014, the peak markup component was highest in January, $3.42 per MWh using adjusted cost offers. Using adjusted cost-offers, the markup component in 2014 increased in every month except April, July and October from 2013. The peak markup component increased from -$2.33 to $3.42 in January.

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

	2013			2014		
	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)	$1.03	$2.85	($0.88)
Feb	($2.53)	($1.43)	($3.67)	$0.34	$2.07	($1.47)
Mar	($1.84)	($0.18)	($3.45)	$0.14	($0.27)	$0.53
Apr	($0.11)	($0.01)	($0.22)	($0.88)	$0.42	($2.37)
May	($0.10)	($0.04)	($0.17)	($0.99)	$0.07	($2.10)
Jun	($0.05)	$0.03	($0.14)	$0.03	$1.30	($1.45)
Jul	($0.08)	($0.01)	($0.15)	($0.98)	($0.38)	($1.68)
Aug	($0.06)	($0.01)	($0.11)	($0.70)	$0.07	($1.51)
Sep	($0.27)	($0.13)	($0.42)	($0.37)	$0.79	($1.64)
Oct	($0.06)	($0.06)	($0.06)	($0.48)	$0.52	($1.69)
Nov	($0.32)	($0.10)	($0.52)	($0.47)	$0.86	($1.61)
Dec	$0.01	$0.00	$0.02	($1.02)	($0.36)	($1.72)
Annual	($0.78)	($0.51)	($1.07)	($0.33)	$0.68	($1.42)

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

	2013			2014		
	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)	$1.80	$3.42	$0.09
Feb	($0.74)	$0.41	($1.93)	$1.44	$2.86	($0.05)
Mar	($0.26)	$1.29	($1.78)	$1.34	$0.64	$2.01
Apr	$0.07	$0.16	($0.03)	$0.51	$1.34	($0.45)
May	$0.02	$0.06	($0.02)	$0.24	$0.85	($0.39)
Jun	$0.07	$0.15	($0.02)	$1.38	$2.31	$0.29
Jul	($0.01)	$0.06	($0.08)	$0.52	$0.92	$0.05
Aug	$0.01	$0.03	($0.01)	$0.64	$1.23	$0.01
Sep	($0.12)	($0.02)	($0.22)	$1.04	$1.94	$0.05
Oct	($0.00)	$0.01	($0.02)	$0.89	$1.62	($0.01)
Nov	($0.15)	($0.01)	($0.29)	$0.80	$1.75	($0.00)
Dec	$0.05	($0.00)	$0.10	$0.41	$0.92	($0.13)
Annual	($0.27)	($0.04)	($0.52)	$0.94	$1.67	$0.15

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Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted offers is shown for each zone in Table 3-57. The markup component of annual average day-ahead price using adjusted offers is shown for each zone in Table 3-58. The markup component of the average day-ahead price increased in all zones from 2013 to 2014. The smallest zonal all hours average markup component using adjusted offers for 2014 was in the DPL Zone, $0.75 per MWh, while the highest was in the BGE Control Zone, $1.12 per MWh. The smallest zonal on peak average markup was in the DPL Control Zone, $1.21 per MWh, while the highest was in the PECO Control Zone, $1.98 per MWh.

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

	2013			2014		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.80)	($0.56)	($1.06)	($0.11)	$0.96	($1.27)
AEP	($0.80)	($0.49)	($1.12)	($0.40)	$0.64	($1.48)
AP	($0.86)	($0.55)	($1.18)	($0.40)	$0.68	($1.53)
ATSI	($0.80)	($0.49)	($1.13)	($0.45)	$0.61	($1.59)
BGE	($0.80)	($0.55)	($1.06)	($0.30)	$0.77	($1.46)
ComEd	($0.72)	($0.44)	($1.02)	($0.43)	$0.41	($1.34)
DAY	($0.81)	($0.49)	($1.16)	($0.43)	$0.59	($1.53)
DEOK	($0.76)	($0.44)	($1.11)	($0.42)	$0.56	($1.44)
DLCO	($0.76)	($0.47)	($1.07)	($0.43)	$0.54	($1.48)
Dominion	($0.78)	($0.53)	($1.06)	($0.36)	$0.68	($1.46)
DPL	($0.84)	($0.52)	($1.17)	($0.43)	$0.29	($1.21)
EKPC	($0.12)	($0.03)	($0.22)	($0.30)	$0.69	($1.28)
JCPL	($0.94)	($0.82)	($1.08)	($0.16)	$0.87	($1.33)
Met-Ed	($0.86)	($0.61)	($1.14)	($0.09)	$1.00	($1.28)
PECO	($0.80)	($0.52)	($1.11)	($0.05)	$1.08	($1.27)
PENELEC	($0.72)	($0.52)	($0.93)	($0.34)	$0.69	($1.50)
Pepco	($0.80)	($0.56)	($1.06)	($0.25)	$0.80	($1.45)
PPL	($0.89)	($0.64)	($1.16)	($0.14)	$0.97	($1.34)
PSEG	($0.77)	($0.51)	($1.07)	($0.14)	$0.93	($1.33)
RECO	($0.75)	($0.46)	($1.08)	($0.16)	$0.86	($1.36)

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

	2013			2014		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.31)	($0.11)	($0.52)	$1.07	$1.88	$0.20
AEP	($0.27)	$0.00	($0.55)	$0.90	$1.65	$0.13
AP	($0.29)	($0.03)	($0.57)	$0.87	$1.66	$0.05
ATSI	($0.27)	($0.01)	($0.56)	$0.86	$1.62	$0.04
BGE	($0.24)	($0.05)	($0.45)	$1.12	$1.91	$0.27
ComEd	($0.25)	$0.01	($0.53)	$0.87	$1.44	$0.26
DAY	($0.28)	($0.00)	($0.58)	$0.91	$1.64	$0.12
DEOK	($0.26)	$0.02	($0.55)	$0.88	$1.56	$0.16
DLCO	($0.26)	($0.01)	($0.53)	$0.81	$1.44	$0.12
Dominion	($0.26)	($0.05)	($0.48)	$0.94	$1.71	$0.13
DPL	($0.31)	($0.05)	($0.58)	$0.75	$1.21	$0.25
EKPC	($0.03)	$0.03	($0.09)	$0.96	$1.65	$0.27
JCPL	($0.42)	($0.31)	($0.54)	$1.04	$1.82	$0.16
Met-Ed	($0.35)	($0.14)	($0.57)	$1.09	$1.92	$0.18
PECO	($0.30)	($0.06)	($0.55)	$1.11	$1.98	$0.18
PENELEC	($0.18)	$0.01	($0.38)	$0.88	$1.65	$0.01
Pepco	($0.24)	($0.04)	($0.46)	$1.11	$1.90	$0.21
PPL	($0.36)	($0.15)	($0.59)	$1.02	$1.88	$0.10
PSEG	($0.29)	($0.07)	($0.54)	$1.00	$1.81	$0.10
RECO	($0.29)	($0.05)	($0.55)	$0.96	$1.74	$0.06

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Markup by Day-Ahead Price Levels

Table 3-59 and Table 3-60 show the average markup component of observed prices, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range. Table 3-59 shows that the average day-ahead markup increased significantly when the day-ahead price is greater or equal to $150 from 2013 to 2014. There were 12 hours when generating resources were marginal in this category in 2013. However, there were 202 hours when generating resources were marginal in this category in 2014. The highest average markup was $437.10 in hour ending 1400 on January 28.

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

	2013		2014	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($1.25)	5.0%	($2.77)	9.7%
$25 to $50	($2.76)	84.5%	($1.20)	70.8%
$50 to $75	$0.69	8.6%	$1.31	12.7%
$75 to $100	$0.03	1.1%	($0.46)	2.5%
$100 to $125	$0.01	0.4%	($6.64)	0.9%
$125 to $150	$0.00	0.1%	$5.66	0.7%
>= $150	($0.30)	0.4%	$10.47	2.8%

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

	2013		2014	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.35)	5.0%	($1.16)	9.7%
$25 to $50	($1.13)	84.5%	$0.57	70.8%
$50 to $75	$1.21	8.6%	$2.29	12.7%
$75 to $100	$0.13	1.1%	$0.09	2.5%
$100 to $125	$0.03	0.4%	($6.00)	0.9%
$125 to $150	$0.01	0.1%	$6.32	0.7%
>= $150	($0.29)	0.4%	$11.45	2.8%

Prices

The conduct of individual market entities within a market structure is reflected in market prices. 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 37.4 percent and 37.8 percent higher in 2014 than in 2013 as a result of higher fuel costs and higher demand.[64] Natural gas prices increased in 2014, especially in the eastern part of PJM. Comparing fuel prices in 2014 to 2013, the price of Northern Appalachian coal remained constant; the price of Central Appalachian coal was 3.6 percent lower; the price of Powder River Basin coal was 9.3 percent higher; the price of eastern natural gas was 36.1 percent higher; and the price of western natural gas was 17.4 percent higher.

PJM real-time energy market prices increased in 2014 compared to 2013. The average LMP was 31.9 percent higher in o2014 than in 2013, $48.22 per MWh versus $36.55 per MWh. The load-weighted average LMP was 37.4 percent higher in 2014 than in 2013, $53.14 per MWh versus $38.66 per MWh.

The fuel-cost adjusted, load-weighted, average LMP in 2014 was 10.7 percent lower than the load-weighted, average LMP for 2014. If fuel costs in 2014 had been the same as in 2013, holding everything else constant, the load-weighted LMP would have been lower, $47.43 per MWh instead of the observed $53.14 per MWh in 2014.

PJM day-ahead energy market prices increased in 2014 compared to 2013. The average LMP was 32.3 percent higher in 2014 than in 2013, $49.15 per MWh versus $37.15 per MWh. The day-ahead load-weighted average LMP was 37.8 percent higher in 2014 than in 2013, $53.62 per MWh versus $38.93 per MWh.[65]

Real-Time LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[66]

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 3-28 shows the hourly distribution of PJM real-time average LMP for 2013 and 2014. There was one hour in 2013 and six hours in 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

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

65 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."

66 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>.

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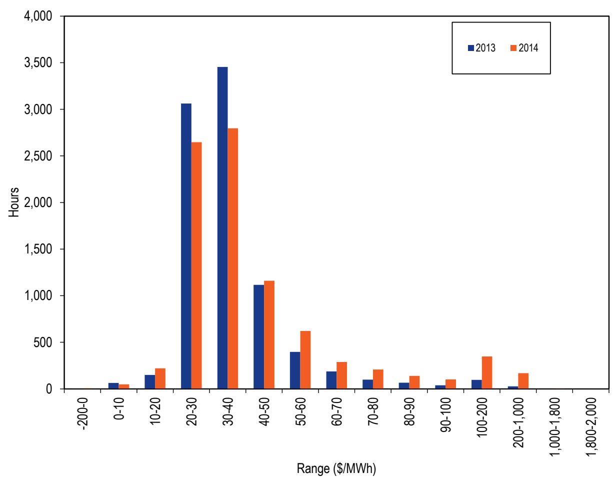
but may also result within a constrained area when inflexible generation exceeds the forecasted load. There were two hours in 2013 and eight hours in of 2014 in which the PJM real-time LMP was $0.00. In 2014, there were six hours in January in which PJM real-time average LMP was greater than $1,000 and one hour in which the real-time LMP was greater $1,800.

Figure 3-28 Average LMP for the PJM Real-Time Energy Market: 2013 and 2014[67]



PJM Real-Time, Average LMP

Table 3-61 shows the PJM real-time, average LMP for each year of the 17 year period 1998 to 2014.[68]

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

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.1%)	(41.1%)	(55.7%)
2010	$44.83	$36.88	$26.20	20.9%	12.7%	53.1%
2011	$42.84	$35.38	$29.03	(4.4%)	(4.1%)	10.8%
2012	$33.11	$29.53	$20.67	(22.7%)	(16.5%)	(28.8%)
2013	$36.55	$32.25	$20.57	10.4%	9.2%	(0.5%)
2014	$48.22	$34.46	$65.08	31.9%	6.8%	216.4%

67 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.

68 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.

Real-Time, Load-Weighted, Average LMP

Higher demand (load) generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than average prices. Load-weighted LMP reflects the average LMP paid for actual MWh consumed during a year. Load-weighted, average LMP is the average of PJM hourly LMP, each weighted by the PJM total hourly load.

PJM Real-Time, Load-Weighted, Average LMP

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

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

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	23.8%	14.3%	58.7%
2011	$45.94	$36.54	$33.47	(5.0%)	(6.6%)	15.8%
2012	$35.23	$30.43	$23.66	(23.3%)	(16.7%)	(29.3%)
2013	$38.66	$33.25	$23.78	9.7%	9.3%	0.5%
2014	$53.14	$36.20	$76.20	37.4%	8.9%	220.4%

Table 3-63 shows zonal real-time, and real-time, load-weighted, average LMP for 2013 and 2014. The real-time, load-weighted, average LMP increased by 37.4 percent compared to 2013.

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Table 3-63 Zone real-time and real-time, load-weighted, average LMP (Dollars per MWh): 2013 and 2014

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2013 Average	2014 Average	Percent Change	2013 Average	2014 Average	Percent Change
AECO	$38.10	$51.17	47.8%	$41.11	$55.77	35.7%
AEP	$34.22	$44.03	28.7%	$35.56	$47.81	34.5%
AP	$36.00	$47.60	32.2%	$37.70	$52.94	40.4%
ATSI	$38.72	$45.39	17.2%	$42.12	$48.60	15.4%
BGE	$40.51	$58.81	45.2%	$43.52	$67.78	55.8%
ComEd	$31.55	$39.54	25.3%	$33.28	$42.04	26.3%
Day	$34.56	$43.77	26.7%	$36.15	$47.36	31.0%
DEOK	$32.94	$41.68	26.6%	$34.35	$45.00	31.0%
DLCO	$34.00	$41.55	22.2%	$35.70	$44.22	23.9%
Dominion	$38.16	$54.50	42.8%	$40.63	$62.99	55.0%
DPL	$39.29	$55.82	42.1%	$42.18	$65.03	54.2%
EKPC	$32.29	$41.75	29.3%	$33.96	$47.88	41.0%
JCPL	$39.04	$50.97	30.5%	$42.98	$56.07	30.4%
Met-Ed	$37.41	$49.60	32.6%	$39.72	$56.08	41.2%
PECO	$37.28	$50.21	34.7%	$39.70	$55.94	40.9%
PENELEC	$37.01	$47.63	28.7%	$38.71	$51.90	34.1%
Pepco	$39.90	$57.34	43.7%	$42.78	$65.61	53.4%
PPL	$37.17	$49.62	33.5%	$39.26	$56.97	45.1%
PSEG	$40.96	$53.71	31.1%	$43.97	$57.90	31.7%
RECO	$41.84	$52.96	26.6%	$45.81	$56.79	24.0%
PJM	$37.15	$48.88	31.6%	$38.66	$53.14	37.4%

Figure 3-29 PJM real-time, load-weighted, average LMP: 2014

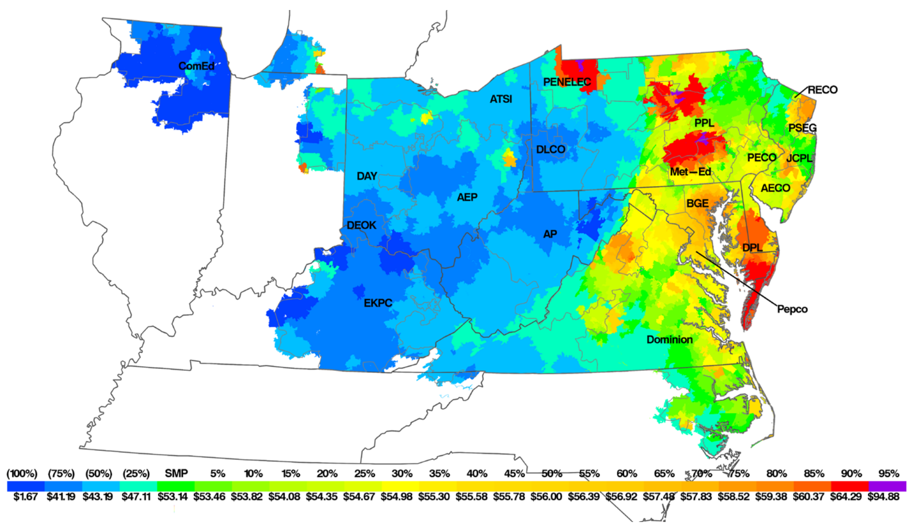
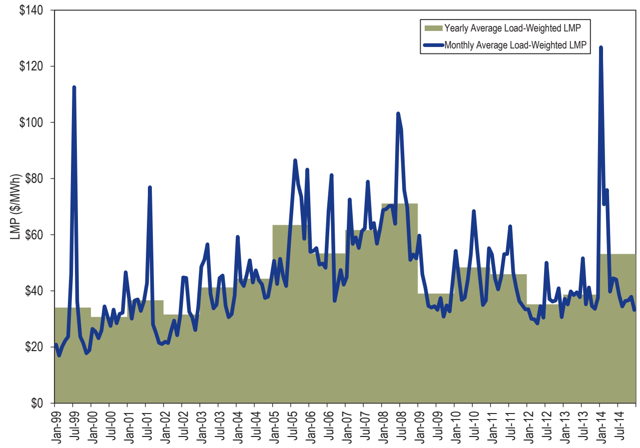


Figure 3-29 is a contour map of the real-time, load-weighted, average LMP in 2014. Green represents the system marginal price (SMP) for each year with each color to the right of green including five percent of the pricing nodes above SMP and each color to the left of green including 25 percent of pricing nodes below SMP. Prices in Eastern MAAC were all higher, on average, than the SMP for 2014.

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

Figure 3-30 shows the PJM real-time monthly and annual load-weighted LMP from 1999 through 2014.

Figure 3-30 PJM real-time, monthly and annual, load-weighted, average LMP: 1999 through 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 prices increased in 2014, especially in the eastern part of PJM. Comparing fuel prices in 2014 to 2013, the price of Northern Appalachian coal remained constant; the price of Central Appalachian coal was 3.6 percent lower; the price of Powder River Basin coal was 9.3 percent higher; the price of eastern natural gas was 36.1 percent higher; and the price of western natural gas was 17.4 percent higher. Figure 3-31 shows monthly average spot fuel prices.[69]

Figure 3-31 Spot average fuel price comparison with fuel delivery charges: 2012 through 2014 ($/MMBtu)

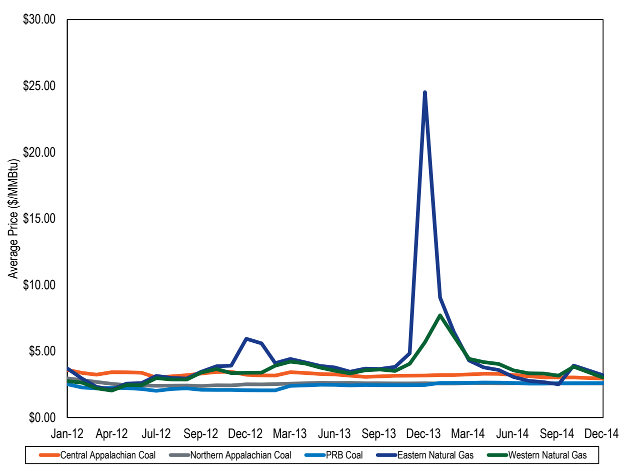


Table 3-64 compares the 2014 PJM real time fuel-cost adjusted, load-weighted, average LMP to the 2013 load-weighted, average LMP. The real time fuel-cost adjusted, load-weighted, average LMP for 2014 was 10.7 percent lower than the real time load-weighted, average LMP for 2014. The real-time, fuel-cost adjusted, load-weighted, average LMP for 2014 was 22.7 percent higher than the real time load-weighted LMP for 2013. If fuel costs in 2014 had been the same as in 2013, holding everything else constant, the real time load-weighted LMP in 2014 would have been lower, $47.43 per MWh instead of the observed $53.14 per MWh.

Table 3-64 PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): year over year

	2014 Load-Weighted LMP	2014 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$53.14	$47.43	(10.7%)
	2013 Load-Weighted LMP	2014 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$38.66	$47.43	22.7%
	2013 Load-Weighted LMP	2014 Load-Weighted LMP	Change
Average	$38.66	$53.14	37.4%

Table 3-65 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 2014. Table 3-65 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 2014.

Table 3-65 Change in PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh) by Fuel-type: year over year

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Coal	$0.09	1.5%
Gas	$5.64	98.7%
Oil	($0.02)	(0.3%)
Other	$0.00	0.0%
Uranium	$0.00	0.0%
Wind	($0.00)	(0.0%)
Total	$5.71	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

69 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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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.[70] 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.[71] 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 3-66, including markup using unadjusted cost offers.[72] Table 3-66 shows that for 2014, 33.4 percent of the load-weighted LMP was the result of coal costs, 35.2 percent was the result of gas costs and 0.70 percent was the result of the cost of emission allowances. Markup was $1.88 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 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 2014 and 2013.

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

	2013		2014		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Gas	$11.56	29.9%	$18.71	35.2%	5.3%
Coal	$18.91	48.9%	$17.73	33.4%	(15.5%)
Ten Percent Adder	$3.21	8.3%	$3.77	7.1%	(1.2%)
Oil	$0.83	2.1%	$2.80	5.3%	3.1%
VOM	$2.36	6.1%	$2.65	5.0%	(1.1%)
Markup	($0.35)	(0.9%)	$1.88	3.5%	4.4%
Emergency DR Adder	($0.21)	(0.5%)	$1.83	3.4%	4.0%
NA	$1.06	2.7%	$1.56	2.9%	0.2%
Increase Generation Adder	$0.15	0.4%	$0.69	1.3%	0.9%
FMU Adder	$0.55	1.4%	$0.62	1.2%	(0.2%)
Ancillary Service Redispatch Cost	$0.19	0.5%	$0.52	1.0%	0.5%
CO_2 Cost	$0.12	0.3%	$0.23	0.4%	0.1%
NO_x Cost	$0.10	0.3%	$0.13	0.2%	(0.0%)
Scarcity Adder	$0.00	0.0%	$0.10	0.2%	0.2%
LPA Rounding Difference	$0.53	1.4%	$0.07	0.1%	(1.2%)
Other	($0.00)	(0.0%)	$0.03	0.1%	0.1%
Municipal Waste	$0.00	0.0%	$0.02	0.0%	0.0%
SO_2 Cost	$0.01	0.0%	$0.01	0.0%	(0.0%)
Market-to-Market Adder	$0.01	0.0%	($0.00)	(0.0%)	(0.0%)
LPA-SCED Differential	($0.20)	(0.5%)	($0.01)	(0.0%)	0.5%
Uranium	$0.00	0.0%	($0.01)	(0.0%)	(0.0%)
Wind	($0.00)	(0.0%)	($0.01)	(0.0%)	(0.0%)
Decrease Generation Adder	($0.15)	(0.4%)	($0.17)	(0.3%)	0.1%
Total	$38.66	100.0%	$53.14	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 3-66 and Table 3-70) markup is simply the difference between the price offer and the cost offer. In the second approach, (Table 3-67 and Table 3-71) the 10 percent markup is removed from the cost offers of coal units.

The components of LMP are shown in Table 3-67, including markup using adjusted cost offers.

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

71 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.

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

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Table 3-67 Components of PJM real-time (Adjusted), annual, load-weighted, average LMP: 2013 and 2014

	2013		2014		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Gas	$11.56	29.9%	$18.71	35.2%	5.3%
Coal	$18.91	48.9%	$17.73	33.4%	(15.5%)
Markup	$1.16	3.0%	$3.32	6.2%	3.2%
Oil	$0.83	2.1%	$2.80	5.3%	3.1%
VOM	$2.36	6.1%	$2.65	5.0%	(1.1%)
Ten Percent Adder	$1.70	4.4%	$2.33	4.4%	(0.0%)
Emergency DR Adder	($0.21)	(0.5%)	$1.83	3.4%	4.0%
NA	$1.06	2.7%	$1.56	2.9%	0.2%
Increase Generation Adder	$0.15	0.4%	$0.69	1.3%	0.9%
FMU Adder	$0.55	1.4%	$0.62	1.2%	(0.2%)
Ancillary Service Redispatch Cost	$0.19	0.5%	$0.52	1.0%	0.5%
CO_2 Cost	$0.12	0.3%	$0.23	0.4%	0.1%
NO_x Cost	$0.10	0.3%	$0.13	0.2%	(0.0%)
Scarcity Adder	$0.00	0.0%	$0.10	0.2%	0.2%
LPA Rounding Difference	$0.53	1.4%	$0.07	0.1%	(1.2%)
Other	($0.00)	(0.0%)	$0.03	0.1%	0.1%
Municipal Waste	$0.00	0.0%	$0.02	0.0%	0.0%
SO_2 Cost	$0.01	0.0%	$0.01	0.0%	(0.0%)
Market-to-Market Adder	$0.01	0.0%	($0.00)	(0.0%)	(0.0%)
LPA-SCED Differential	($0.20)	(0.5%)	($0.01)	(0.0%)	0.5%
Uranium	$0.00	0.0%	($0.01)	(0.0%)	(0.0%)
Wind	($0.00)	(0.0%)	($0.01)	(0.0%)	(0.0%)
Decrease Generation Adder	($0.15)	(0.4%)	($0.17)	(0.3%)	0.1%
Total	$38.66	100.0%	$53.14	100.0%	0.0%

Day-Ahead LMP

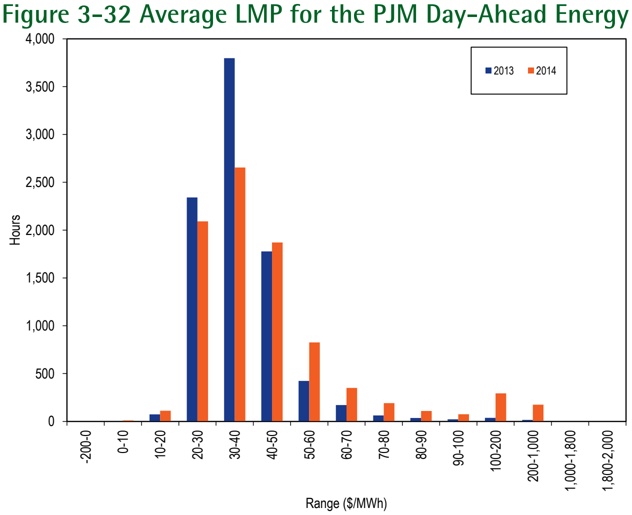
Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[73]

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-32 shows the hourly distribution of PJM day-ahead average LMP for the 2013 and 2014.

Figure 3-32 Average LMP for the PJM Day-Ahead Energy Market: 2013 and 2014



73 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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PJM Day-Ahead, Average LMP

Table 3-68 shows the PJM day-ahead, average LMP for each year of the 14-year period 2001 to 2014.

Table 3-68 PJM day-ahead, average LMP (Dollars per MWh): 2001 through 2014

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$32.75	$27.05	$30.42	NA	NA	NA
2002	$28.46	$23.28	$17.68	(13.1%)	(14.0%)	(41.9%)
2003	$38.73	$35.22	$20.84	36.1%	51.3%	17.8%
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.4%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	(44.0%)	(40.3%)	(56.6%)
2010	$44.57	$39.97	$18.83	20.5%	13.7%	40.6%
2011	$42.52	$38.13	$20.48	(4.6%)	(4.6%)	8.8%
2012	$32.79	$30.89	$13.27	(22.9%)	(19.0%)	(35.2%)
2013	$37.15	$34.63	$15.46	13.3%	12.1%	16.5%
2014	$49.15	$38.10	$51.88	32.3%	10.0%	235.6%

Day-Ahead, Load-Weighted, Average LMP

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

PJM Day-Ahead, Load-Weighted, Average LMP

Table 3-69 shows the PJM day-ahead, load-weighted, average LMP for each year of the 14-year period 2001 to 2014.

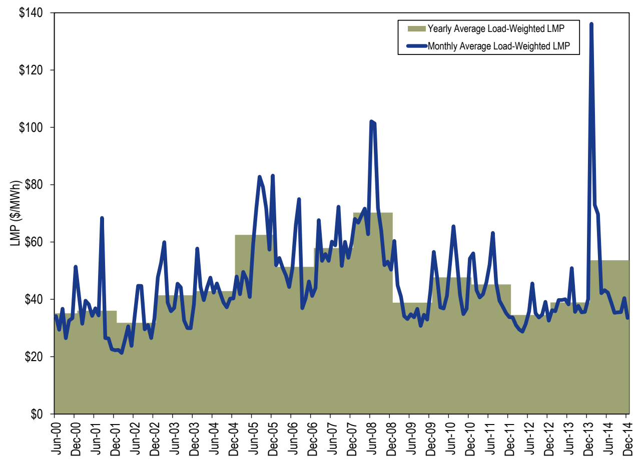
Table 3-69 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): 2001 through 2014

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.01	$29.02	$37.48	NA	NA	NA
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	(44.7%)	(41.7%)	(57.7%)
2010	$47.65	$42.06	$20.59	22.7%	14.7%	46.8%
2011	$45.19	$39.66	$24.05	(5.2%)	(5.7%)	16.8%
2012	$34.55	$31.84	$15.48	(23.5%)	(19.7%)	(35.6%)
2013	$38.93	$35.77	$18.05	12.7%	12.3%	16.6%
2014	$53.62	$39.84	$59.62	37.8%	11.4%	230.4%

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

Figure 3-33 shows the PJM day-ahead, monthly and annual, load-weighted LMP from 2000 through 2014.[74]

Figure 3-33 Day-ahead, monthly and annual, load-weighted, average LMP: 2000 through 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.

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

74 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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that participate in RGGI: Delaware and Maryland.[75] 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 3-70, including markup using unadjusted cost offers.

Table 3-70 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In 2014, 22.1 percent of the load-weighted LMP was the result of coal cost, 19.9 percent of the load-weighted LMP was the result of gas cost, 11.6 percent was the result of the up-to congestion transaction cost, 17.2 percent was the result of DEC bid cost and 15.2 percent was the result of INC bid cost. The contribution of up-to congestion transactions decreased on September 8, 2014, as a result of the FERC's UTC uplift refund notice which became effective on that date.[76]

Table 3-70 Components of PJM day-ahead, (unadjusted) annual, load-weighted, average LMP (Dollars per MWh): 2013 and 2014

	2013		2014		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$4.67	12.0%	$11.33	21.1%	9.1%
Gas	$2.23	5.7%	$10.67	19.9%	14.2%
DEC	$1.89	4.9%	$9.20	17.2%	12.3%
INC	$1.31	3.4%	$8.16	15.2%	11.9%
Up-to Congestion Transaction	$28.00	71.9%	$6.21	11.6%	(60.4%)
Ten Percent Cost Adder	$0.74	1.9%	$2.47	4.6%	2.7%
Dispatchable Transaction	$0.13	0.3%	$2.25	4.2%	3.9%
VOM	$0.50	1.3%	$1.46	2.7%	1.5%
Price Sensitive Demand	$0.05	0.1%	$0.85	1.6%	1.5%
Oil	($0.00)	(0.0%)	$0.78	1.5%	1.5%
FMU Adder	$0.03	0.1%	$0.33	0.6%	0.5%
Import	$0.00	0.0%	$0.18	0.3%	0.3%
CO2	$0.02	0.0%	$0.15	0.3%	0.2%
NOx	$0.02	0.0%	$0.08	0.1%	0.1%
DASR Offer Adder	$0.00	0.0%	$0.05	0.1%	0.1%
Municipal Waste	$0.00	0.0%	$0.02	0.0%	0.0%
SO2	$0.00	0.0%	$0.01	0.0%	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.00)	(0.0%)	($0.01)	(0.0%)	(0.0%)
DASR LOC Adder	$0.01	0.0%	($0.03)	(0.1%)	(0.1%)
Markup	($0.78)	(2.0%)	($0.33)	(0.6%)	1.4%
NA	$0.11	0.3%	($0.21)	(0.4%)	(0.7%)
Total	$38.93	100.0%	$53.62	100.0%	(0.0%)

Table 3-71 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.

75 New Jersey withdrew from RGGI, effective January 1, 2012.
76 See 18 CFR § 385.213 (2014).

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

	2013		2014		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$4.66	12.0%	$11.31	21.1%	9.1%
Gas	$2.23	5.7%	$10.67	19.9%	14.2%
DEC	$1.89	4.9%	$9.20	17.2%	12.3%
INC	$1.31	3.4%	$8.16	15.2%	11.9%
Up-to Congestion Transaction	$28.00	71.9%	$6.21	11.6%	(60.4%)
Dispatchable Transaction	$0.13	0.3%	$2.25	4.2%	3.9%
VOM	$0.50	1.3%	$1.46	2.7%	1.5%
Ten Percent Cost Adder	$0.23	0.6%	$1.23	2.3%	1.7%
Markup	($0.27)	(0.7%)	$0.94	1.7%	2.4%
Price Sensitive Demand	$0.05	0.1%	$0.85	1.6%	1.5%
Oil	($0.00)	(0.0%)	$0.78	1.4%	1.5%
FMU Adder	$0.03	0.1%	$0.33	0.6%	0.5%
Import	$0.00	0.0%	$0.18	0.3%	0.3%
CO2	$0.02	0.0%	$0.15	0.3%	0.2%
NOx	$0.02	0.0%	$0.08	0.1%	0.1%
DASR Offer Adder	$0.00	0.0%	$0.05	0.1%	0.1%
Municipal Waste	$0.00	0.0%	$0.02	0.0%	0.0%
SO2	$0.00	0.0%	$0.01	0.0%	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.00)	(0.0%)	($0.01)	(0.0%)	(0.0%)
DASR LOC Adder	$0.01	0.0%	($0.03)	(0.1%)	(0.1%)
NA	$0.11	0.3%	($0.21)	(0.4%)	(0.7%)
Total	$38.93	100.0%	$53.62	100.0%	(0.0%)

Price Convergence

The introduction of the PJM Day-Ahead Energy Market created the possibility that competition, exercised through the use of virtual offers and bids, would tend to cause prices in the Day-Ahead and Real-Time Energy Markets to converge. Convergence is not the goal of virtual trading, but it is a possible outcome. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market. Price convergence does not necessarily mean a zero or even a very small difference in prices between Day-Ahead and Real-Time Energy Markets. There may be factors, from operating reserve charges to differences in risk that result in a competitive, market-based differential. In addition, convergence in the sense that day-ahead and real-time prices are equal at individual buses or aggregates on a day to day basis is not a realistic expectation as a result of uncertainty, lags in response time and modeling differences, such as differences in modeled contingencies and marginal loss calculations, between the Day-Ahead and Real-Time Energy Market.

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

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

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

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

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

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

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divergence on one side and to price convergence on the other side.

Table 3-72 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 2013 and 2014. In 2014, 55.5 percent of all cleared UTC transactions were net profitable, with 67.6 percent of the source side profitable and 33.8 percent of the sink side profitable.

Table 3-72 Cleared UTC profitability by source and sink point: 2013 and 2014[77]

	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	Profitable UTC	Profitable Source	Profitable Sink
2013	14,736,798	8,162,744	9,883,565	4,994,347	55.4%	67.1%	33.9%
2014	19,871,705	11,023,683	13,424,464	6,710,512	55.5%	67.6%	33.8%

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.

Table 3-73 Day-ahead and real-time average LMP (Dollars per MWh): 2013 and 2014[78]

	2013				2014			
	Day Ahead	Real Time	Difference	Percent of Real Time	Day Ahead	Real Time	Difference	Percent of Real Time
Average	$37.15	$36.55	($0.60)	(1.6%)	$49.15	$48.22	($0.93)	(1.9%)
Median	$34.63	$32.25	($2.38)	(7.4%)	$38.10	$34.46	($3.64)	(10.6%)
Standard deviation	$15.46	$20.57	$5.11	24.8%	$51.88	$65.08	$13.20	20.3%
Peak average	$43.63	$43.24	($0.39)	(0.9%)	$60.65	$59.12	($1.54)	(2.6%)
Peak median	$39.67	$36.75	($2.92)	(8.0%)	$44.55	$40.50	($4.05)	(10.0%)
Peak standard deviation	$19.20	$25.69	$6.49	25.3%	$64.56	$81.78	$17.22	21.1%
Off peak average	$31.50	$30.72	($0.78)	(2.5%)	$39.12	$38.72	($0.41)	(1.1%)
Off peak median	$30.19	$28.44	($1.76)	(6.2%)	$31.37	$29.39	($1.98)	(6.7%)
Off peak standard deviation	$7.59	$11.99	$4.40	36.7%	$34.48	$43.64	$9.16	21.0%

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 3-35).

Table 3-73 shows that the difference between the average real-time price and the average day-ahead price was -$0.60 per MWh in 2013, and -$0.93 per MWh in 2014. The difference between average peak real-time price and the average peak day-ahead price was -$0.39 per MWh in 2013 and -$1.54 per MWh in 2014.

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 3-74 shows the difference between the Real-Time and the Day-Ahead Energy Market prices for each year of the 14-year period 2001 to 2014.

77 Calculations exclude PJM administrative charges.

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

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Table 3-74 Day-ahead and real-time average LMP (Dollars per MWh): 2001 through 2014

	Day Ahead	Real Time	Difference	Percent of Real Time
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.3%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%
2010	$44.57	$44.83	$0.26	0.6%
2011	$42.52	$42.84	$0.32	0.7%
2012	$32.79	$33.11	$0.32	1.0%
2013	$37.15	$36.55	($0.60)	(1.6%)
2014	$49.15	$48.22	($0.93)	(1.9%)

Table 3-75 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for 2007 through 2014.

Table 3-75 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): 2007 through 2014

	2007		2008		2009		2010		2011	
LMP	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%
($1,000) to ($750)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($750) to ($500)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($500) to ($450)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($450) to ($400)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($400) to ($350)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($350) to ($300)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($300) to ($250)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($250) to ($200)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($200) to ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.01%
($150) to ($100)	0	0.00%	1	0.01%	0	0.00%	0	0.00%	2	0.03%
($100) to ($50)	33	0.38%	88	1.01%	3	0.03%	13	0.15%	49	0.59%
($50) to $0	4,600	52.89%	5,120	59.30%	5,108	58.34%	5,543	63.42%	5,614	64.68%
$0 to $50	3,827	96.58%	3,247	96.27%	3,603	99.47%	3,004	97.72%	2,880	97.56%
$50 to $100	255	99.49%	284	99.50%	41	99.94%	164	99.59%	185	99.67%
$100 to $150	31	99.84%	37	99.92%	5	100.00%	25	99.87%	21	99.91%
$150 to $200	5	99.90%	4	99.97%	0	100.00%	9	99.98%	2	99.93%
$200 to $250	1	99.91%	2	99.99%	0	100.00%	2	100.00%	3	99.97%
$250 to $300	3	99.94%	0	99.99%	0	100.00%	0	100.00%	0	99.97%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.97%
$350 to $400	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.97%
$400 to $450	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	99.97%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.97%
$500 to $750	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%
$750 to $1,000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$1,000 to $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
>= $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

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Table 3-75 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): 2007 through 2014 *(continued)*

	2012		2013		2014	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%	0	0.00%
($1,000) to ($750)	0	0.00%	0	0.00%	2	0.02%
($750) to ($500)	0	0.00%	0	0.00%	3	0.06%
($500) to ($450)	0	0.00%	0	0.00%	1	0.07%
($450) to ($400)	0	0.00%	0	0.00%	6	0.14%
($400) to ($350)	0	0.00%	0	0.00%	5	0.19%
($350) to ($300)	0	0.00%	0	0.00%	5	0.25%
($300) to ($250)	0	0.00%	0	0.00%	6	0.32%
($250) to ($200)	1	0.01%	1	0.01%	14	0.48%
($200) to ($150)	4	0.06%	3	0.05%	14	0.64%
($150) to ($100)	6	0.13%	5	0.10%	45	1.15%
($100) to ($50)	17	0.32%	9	0.21%	91	2.19%
($50) to $0	5,576	63.80%	5,994	68.63%	5,829	68.73%
$0 to $50	3,061	98.65%	2,659	98.98%	2,525	97.56%
$50 to $100	82	99.58%	64	99.71%	120	98.93%
$100 to $150	17	99.77%	12	99.85%	39	99.37%
$150 to $200	12	99.91%	10	99.97%	18	99.58%
$200 to $250	5	99.97%	1	99.98%	9	99.68%
$250 to $300	1	99.98%	2	100.00%	8	99.77%
$300 to $350	2	100.00%	0	100.00%	3	99.81%
$350 to $400	0	100.00%	0	100.00%	3	99.84%
$400 to $450	0	100.00%	0	100.00%	2	99.86%
$450 to $500	0	100.00%	0	100.00%	0	99.86%
$500 to $750	0	100.00%	0	100.00%	7	99.94%
$750 to $1,000	0	100.00%	0	100.00%	0	99.94%
$1,000 to $1,250	0	100.00%	0	100.00%	1	99.95%
>= $1,250	0	100.00%	0	100.00%	4	100.00%

Figure 3-34 shows the hourly differences between day-ahead and real-time hourly LMP in 2014.

Figure 3-34 Real-time hourly LMP minus day-ahead hourly LMP: 2014

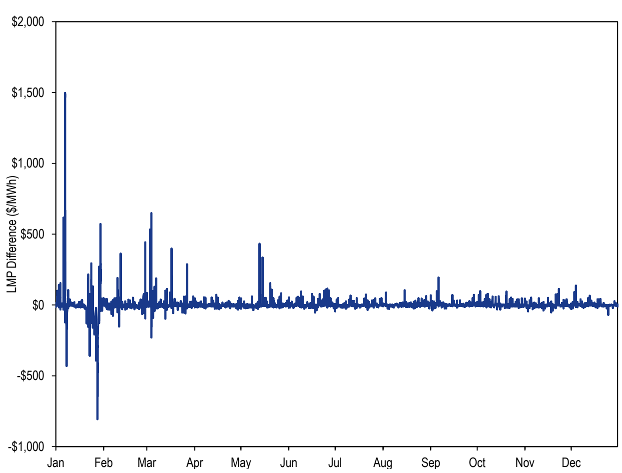

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Figure 3-35 shows the monthly average differences between the day-ahead and real-time LMP in 2014.

Figure 3-35 Monthly average of real-time minus day-ahead LMP: 2014

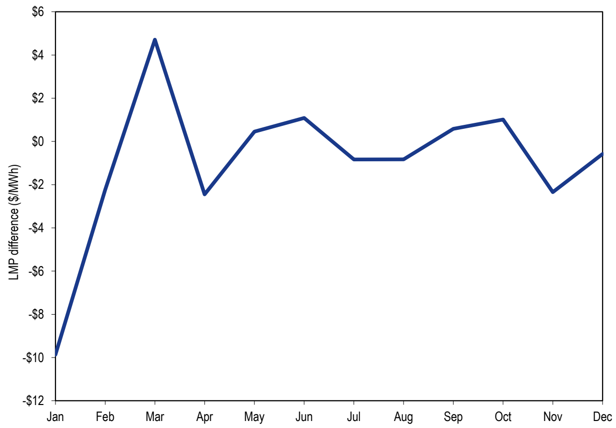
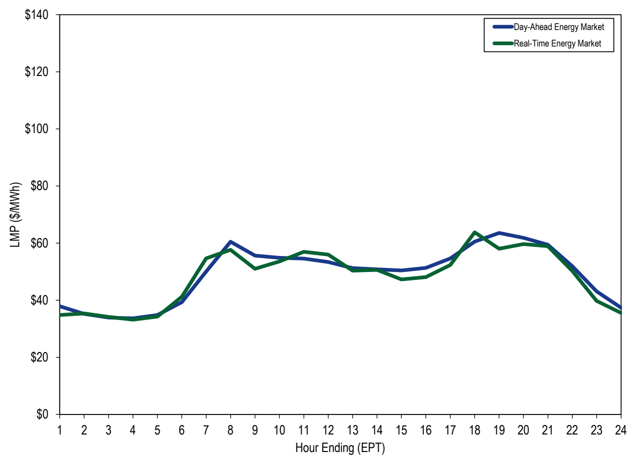


Figure 3-36 shows day-ahead and real-time LMP on an average hourly basis for 2014.

Figure 3-36 PJM system hourly average LMP: 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 resulted in low reserve margins and associated shortage pricing events, and high uplift payments in January. Table 3-76 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in 2013 and 2014.

Table 3-76 Summary of emergency events declared, 2013 and 2014

	Number of days events declared	
Event Type	2013	2014
Cold Weather Alert	7	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 2014 compared to only seven days in 2013.[79] 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 2014 compared to 17 days in 2013.[80] 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.

PJM declared maximum emergency generation alerts on six days in 2014 compared to four days in 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

79 See PJM. "Manual 13: Emergency Operations," Revision 57 (January 1, 2015), Section 3.3 Cold Weather Alert, p. 46.

80 See PJM. "Manual 13: Emergency Operations," Revision 57 (January 1, 2015), Section 3.4 Hot Weather Alert, p. 46.

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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.[81] This means that if PJM directs members to load maximum emergency generation during the operating day, the resources must be able to increase generation above the maximum economic level of their offer.

PJM declared a primary reserve alert on two days in 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 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 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 2014 compared to one day in 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 2014 compared to five days in 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 2014 were 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 2014 compared to five days in 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 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 2014. On January 7, PJM requested bids for emergency energy between 0600 and 1100 and again between hours 1700 to 2100. PJM also requested bids for emergency energy on January 8 and January 23, but did not purchase any emergency energy.

PJM did not recall energy from PJM capacity resources that were exporting energy during emergency conditions in 2014.

PJM issued a voltage reduction action on one day (January 6) in 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

81 See PJM. "Manual 13: Emergency Operations," Revision 57 (January 1, 2015), Section 2.3.1 Advance Notice Emergency Procedures: Alerts, p. 16.

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locational marginal prices until the voltage reduction action has been terminated.

There were 37 synchronized reserve events in 2014 compared to 18 in 2013.[82] Of the 37, 27 were disturbances caused by line trips. In 2013, there were six synchronized reserve events in the winter months, and seven in the summer months. In 2014 there were 17 synchronized reserve events in the winter months and 2 in the summer months. Synchronized Reserve events may occur at any time of the year due to sudden loss of generation or transmission facilities and do not necessarily coincide with capacity emergency conditions such as maximum generation emergency events or emergency load management events.

Table 3-77 provides a description of PJM declared emergency procedures.

82 See *2014 State of the Market Report for PJM*, Section 10: Ancillary Service Markets for details on the spinning events.

Table 3-77 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.

Table 3-78 shows the dates on which emergency alerts and warnings were declared as well as emergency actions were implemented in 2014. In 2013, all the maximum generation emergency alerts (four days), maximum generation emergency actions (five days), and emergency load management actions (five days) were declared in the summer (July and September). In 2014, all the maximum generation emergency alerts (six

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days), maximum generation emergency actions (eight days), and emergency load management actions (six days) were declared in the winter (January and March).

Table 3-78 PJM declared emergency alerts, warnings and actions: 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										

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Table 3-78 PJM declared emergency alerts, warnings and actions: 2014 *(continued)*

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
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									

Scarcity and Scarcity Pricing

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

On October 1, 2012, PJM introduced a new administrative scarcity pricing regime. Under the current PJM market rules, shortage pricing conditions are triggered when there is a shortage of synchronized or primary reserves in the RTO or in the Mid-Atlantic and Dominion (MAD) subzone. In times of reserve shortage, the value of reserves is included as a penalty factor in the optimization and in the price of energy.[83] Shortage pricing is also triggered when PJM issues a voltage reduction action or a manual load dump action for a reserve zone or a reserve sub-zone. When shortage pricing is triggered, the primary reserve penalty factor and the synchronized reserve penalty factor are incorporated in the calculation of the synchronized and non-synchronized reserve market clearing prices and the locational marginal price.

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

January 6, 2014

On January 3, PJM declared a cold weather alert for January 6 for the RTO excluding the Mid-Atlantic region and Dominion Control Zone. On January 6, PJM declared a voltage reduction warning and reduction of non-critical plant load at 1927 for the RTO. At 1933, PJM declared a maximum emergency generation action. At 1950 EPT, PJM

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

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declared a five percent voltage reduction action for the RTO that triggered shortage pricing. The event lasted for less than an hour and was cancelled at 2045.

January 7, 2014

On January 6, at 1125, PJM issued a maximum emergency generation alert for the RTO for January 7. At 0055 on January 7, a primary reserve warning was issued for the RTO. On January 7 at 0153, PJM issued a request to purchase emergency energy for delivery between 0600 and 1100.[84] At 0251, PJM declared a voltage reduction warning and reduction of non-critical plant load for the RTO. At 0430, PJM declared a maximum emergency generation action for the RTO. Also at 0430, PJM issued emergency mandatory load management for both short lead and long lead demand resources for the RTO. Shortage pricing was triggered at 0725. It ended at 1220 when primary and synchronized reserves increased to greater than the required levels. The primary reserve warning, voltage reduction warning and the maximum emergency generation action were cancelled at 1214.

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

Waivers of Tariff Requirements

On January 3, 2014, PJM submitted two requests for waivers of limits on information sharing in section 18.17.1 of the Operating Agreement (OA). The waivers would allow PJM to share market sensitive information with interstate natural gas pipelines to coordinate for ensuring reliability during the period of extreme winter weather. Section 18.17.1 of the OA prohibits PJM from disclosing to its members or third parties, confidential or market sensitive information of a member without prior authorization. The request for waiver in docket number ER14-952-000 was for a limited period in light of the extreme weather conditions forecast during the period from January 4, 2014 through January 10, 2014.[85] The request for waiver in docket number ER14-951-000 was for the period from January 11, 2014 through the end of the winter heating season.[86] On January 6, the commission issued an order granting the limited waiver and on January 17, the commission issued an order granting the longer term waiver allowing PJM to communicate and coordinate unit commitment schedules with interstate gas pipeline operators.[87,88]

On January 23, 2014, PJM submitted two requests for waivers of provisions in the PJM Tariff related to the $1,000/MWh cap on cost-based energy offers. In docket number ER14-1144-000, PJM requested a waiver to be effective January 24, 2014, that would allow generators to be made whole if the offer cap prevented the recovery of actual marginal energy costs.[89] On January 24, the commission granted the waiver while directing the MMU to submit an informational filing within 30 days of the expiration of the waiver with data on the amount of MWh that cleared above the cap and the cost of such energy.[90] In docket number ER14-1145-000, PJM requested a waiver of the $1,000/MWh energy offer price cap in order to allow cost-based offers to reflect potential high fuel prices through March 31, 2014.91 On February 11, the commission granted the waiver lifting the cap on energy cost based offers effective through March 31.[92]

The MMU submitted a report on March 26, 2014, pursuant to the January 24 commission order.[93] The MMU reported that there were seven units belonging to three market participants that initially requested make whole payments associated with incurred costs that were not recovered as a result of the $1,000 per MWh offer cap, of which three units subsequently withdrew their requests. The total additional make whole payment requested by the participants was $583,774.38. The MMU analysis concluded that the total additional make whole payment required was $9,118.43. The primary

84 See PJM. "Manual 13: Emergency Operations," Revision 57 (January 1, 2015), pp. 23-25.

85 "Request for waiver and expedited relief of PJM Interconnection, L.L.C.," Docket No. ER14-952-000 (January 3, 2014).

86 "Request for waiver of PJM Interconnection, L.L.C.," Docket No. ER14-951-000 (January 3, 2014).

87 146 FERC ¶ 61,003 (2014).

88 146 FERC ¶ 61,033 2014).

89 "Request of PJM Interconnection, L.L.C. for waiver and for commission action by January 24, 2014," Docket No. ER14-1144-000 (January 23, 2014).

90 146 FERC ¶ 61,041 (2014).

91 "Request of PJM Interconnection, L.L.C. for waiver, request for 7-day comment period, and request for commission action by February 10, 2014," Docket No. ER14-1145-000 (January 23, 2014).

92 146 FERC ¶ 61,078 (February 11, 2014).

93 "Informational Filing re Waiver to Permit Make-Whole Payments," Docket No. ER14-1144-000 (March 26, 2014).

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reasons for the differences between the participants' estimates and the MMU's calculations were that the MMU calculations recognized that the ten percent adder was not part of fuel costs, the actual fuel costs incurred were less then claimed and the actual unit heat rates were better than claimed.

The MMU submitted a report on April 30, 2014, pursuant to the February 11 commission order.[94] The MMU found that there were no cost-based energy offers submitted with incremental curve offer components above $1,000 per MWh. There were no LMPs above $1,000 per MWh as a direct result of the waiver granted by the commission. The total offer or operating rate at a specified output level is the sum of the total incremental costs to operate at that level as determined from the incremental curve and the no load component, divided by the output level in MWh. The $1,000 per MWh offer cap refers to the complete offer of the unit, rather than just the incremental part of the offer. An offer cap that applied solely to the incremental rate would be easy to avoid by increasing the no load rate. A generation owner may change the startup and no load components of price-based offers only semiannually on defined dates, while the startup and no load components of cost-based offers may be changed daily as costs change and the cost-based startup and no load components of price-based offers may also be changed daily as costs change.[95] The definition of the no load component of cost-based offers does not permit the transfer of costs from the incremental curve component to the no load component. The MMU's review showed that some units' energy offers, including the no load and incremental components, did exceed $1,000 per MWh but that none of those units ran with those offers, none of these offers directly affected energy market prices and no uplift payments were made to those units based on those costs.

Emergency events in January 2014

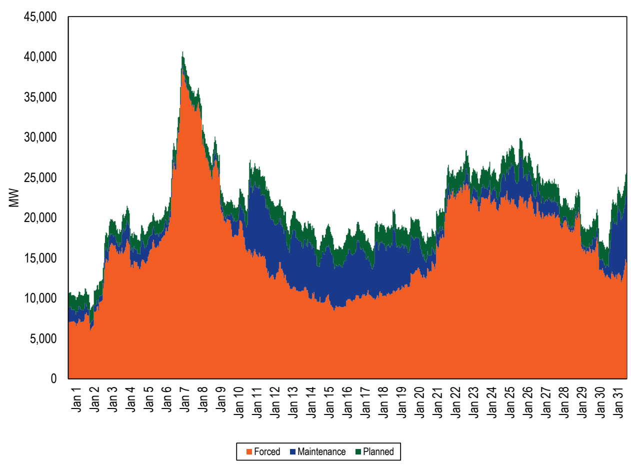
Extreme cold weather conditions in January resulted in record PJM winter peak loads. The high demand combined with high forced outage rates, and supply interruptions for natural gas fueled generation resulted in low reserve margins and associated shortage pricing events, and high uplift payments in January.

In the period from January 6 through January 8, there were extreme cold weather conditions in the PJM territory. On January 3, PJM issued cold weather alerts for January 6 (PJM territory except Mid-Atlantic and Dominion regions) and January 7 (for the RTO). PJM winter load reached a new peak on January 7 for the hour ending 1900 at 140,467 MW.

Generator outages

The maximum level of generating capacity on outage was 40,665 MW on January 7, 2014, for the hour ending 0900, of which 38,452 MW were forced outages. During the period from January 17 through January 29, 2014, the maximum MW on outage was 29,912 MW on January 26 for the hour ending 0300. While outage levels were better during the second half of January, outage levels were still well above average. Figure 3-37 shows the total MW on outage in January 2014 by the type of outage.

Figure 3-37 Generator outages in January 2014 by type of outage



94 "Report on PJM Energy Market Offers, February 11 to March 31, 2014," Docket No. ER14-1145-000 (April 30, 2014).
95 See PJM.OA Schedule 1 § 1.9.7(b).

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Figure 3-38 shows the total MW on outage by unit fuel source.

Figure 3-38 Generator outages in January 2014 by unit fuel source

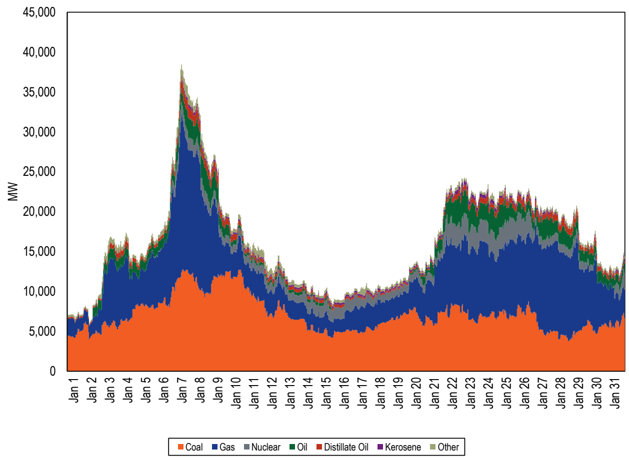


Figure 3-39 highlights all fuel-related forced outages by category. During the hour ending 1900 on January 7, the winter peak load hour, 15,020 MW of generation was forced out due to fuel-related causes out of a total of 34,603 MW of generation on forced outage.

Figure 3-40 shows the forced outage MW in January by cause. Lack of fuel is the largest cause of forced outages. In addition to the lack of fuel for natural gas fired generation, some coal fired units were on forced outage because the gas required to start was not available. During the hour ending 1900 on January 7, the winter peak load hour, 10,404 MW of generation was forced out due to lack of fuel out of a total of 34,603 MW of generation on forced outage.

Figure 3-39 Fuel related forced outage MW in January 2014 by category

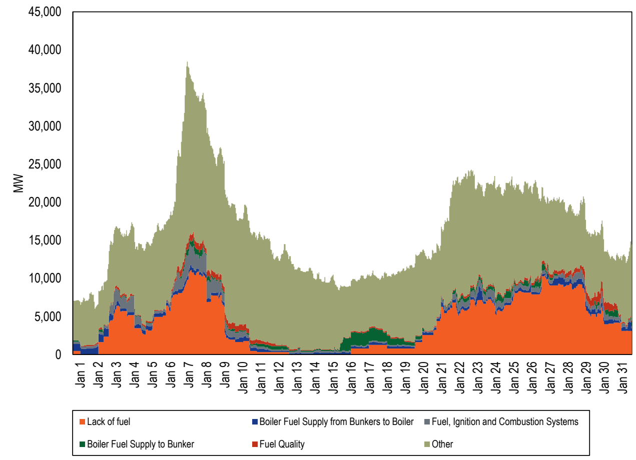
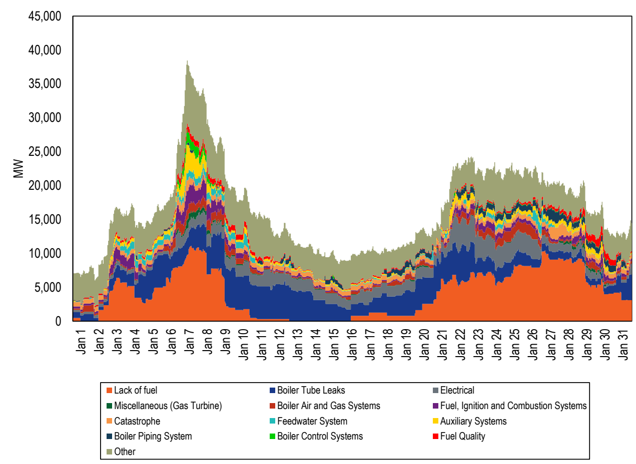


Figure 3-40 Forced outage MW in January 2014 by cause



Natural gas supply and prices

As of January 1, 2014, gas fired generation was 29.2 percent (53,395.0 MW) of the total installed PJM capacity (183,095.2 MW).[96] The extreme cold weather conditions and the associated high demand for natural gas led to supply constraints on the gas transmission system which resulted in natural gas price volatility and interruptions to customers without firm transportation. Figure 3-41 shows the average daily price of delivered natural gas for eastern and western parts of PJM service territory in January.

96 *2014 Quarterly State of the Market Report for PJM: January through March*, Section 5: Capacity Market, at Installed Capacity.

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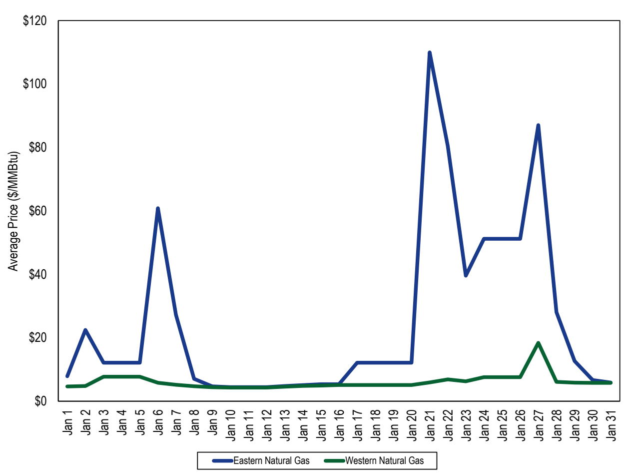
During the first three months of 2014, a number of interstate gas pipelines that supply fuel for generators in the PJM service territory issued notices for lack of non-firm gas availability.[97] These notices include warnings of operational flow orders (OFO) and actual OFOs. OFOs restrict the provision of gas to 24 hour ratable takes which means that hourly nominations must be the same for each of the 24 hours in the day, with penalties for deviating from the nomination amounts. Pipelines also enforce strict balancing constraints which limit the ability of gas users (without no-notice service) to deviate from the 24 hour ratable take and which limit the ability of users to have access to unused gas.

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

Figure 3-41 Average daily delivered price for natural gas: January 2014 ($/MMBtu)

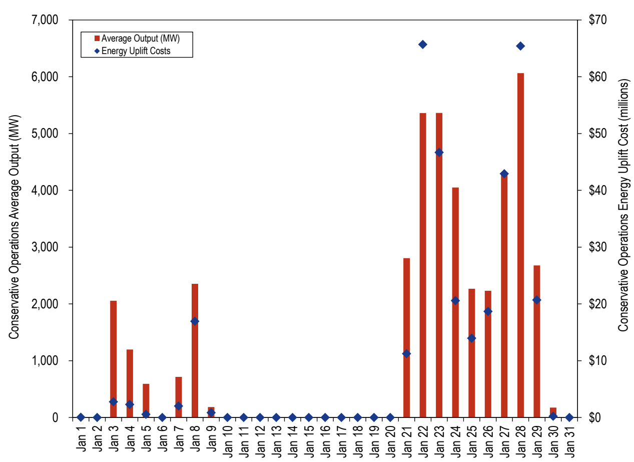


97 See PJM. *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (May 8, 2014) at 'Appendix C' for details on critical notices by natural gas pipelines serving the PJM territory.

Conservative operations and energy uplift costs

Energy uplift costs due to conservative operations were a primary cause of high energy uplift costs in January, especially between January 21 and January 29. PJM committed units for conservative operations in late January as a result of experienced high forced outage rates and fuel procurement issues for gas fired generators earlier in the month, on January 6 and January 7. PJM invokes conservative operations when there is expected to be significant stress on the grid. Some of the actions taken by PJM during conservative operations include notifying and committing units before the operating day to ensure or confirm their availability.[98] Balancing operating reserve credits paid to units committed before the operating day for reliability purposes in January were $331.4 million or 54.4 percent of all energy uplift costs in the month. Figure 3-42 shows the average output in MW committed for conservative operations before the operating day and the balancing operating reserve credits paid to those units. PJM's commitment of units for conservative operations means that PJM committed the units based on concern about meeting load during peak hours, providing additional reserves as a buffer against a disturbance in the system and reducing operational uncertainty in general. Energy uplift credits increased when units were kept online even when noneconomic as a result of uncertainty about the ability to restart, and uncertainties about the ability to procure natural gas.

Figure 3-42 Conservative operations average output and energy uplift costs: January 2014



98 See PJM. "Manual 13: Emergency Operations," Revision 57 (January 1, 2015), Section 3.2 Conservative Operations, p. 45.

Parameter Limited Schedules

All capacity resources in PJM are required to submit at least one cost based offer. All cost based offers are parameter limited in accordance with the Parameter Limited Schedule (PLS) matrix or to the level of a prior approved exception.[99] All capacity resources that choose to offer price based schedules are required to make available at least one price based parameter limited schedule. This schedule is to be used by PJM for committing generation resources when a maximum emergency generation alert is declared. In the first three months of 2014, even though PJM issued maximum emergency alerts on 6 days, PJM did not use price based parameter limited schedules during any of these event days.

During these extreme weather events, some of the parameters were notified to PJM dispatchers verbally by resource owners in place of using the eMKT tool. Key parameters like startup and notification time are not limited by the PLS matrix. Some resource owners told PJM that they needed extended notification times. These notification times were, in certain cases, multiple days in advance of the operating day and had no clear relationship to physical requirements of the units. The long notification times forced PJM to commit resources multiple days in advance of the operating day with the associated uncertainty about the need for these resources to run on that operating day. When these units were committed out of the money for reliability reasons, they received make whole payments that resulted in high uplift charges.

Day-ahead and real-time LMP

Prices in January fluctuated during the cold weather events. (Figure 3-43) Real-time prices were higher than day-ahead prices during January 7 and 8. Day-ahead prices were higher than real-time prices at times in the later part of January. (Figure 3-44) The relationship between day-ahead and real-time prices is a complex function of PJM actions, market supply and demand conditions, participant behavior and participant expectations.

99 See PJM, OATT, § 6.6 Minimum Generator Operating Parameters - Parameter-Limited Schedules, (September 10, 2014), pp. 1937- 1940.

Figure 3-43 PJM real-time and day-ahead hourly LMP: January 2014

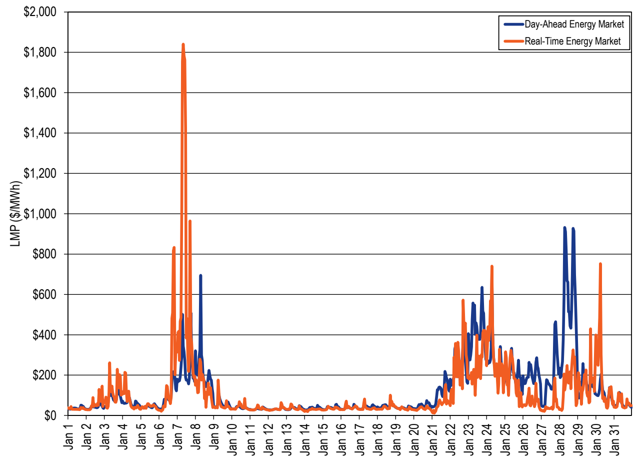
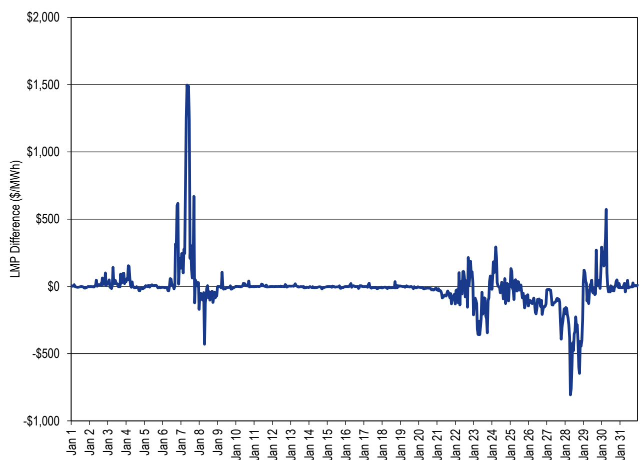


Figure 3-44 Real-time hourly LMP minus day-ahead hourly LMP: January 2014



The real-time average hourly LMP on January 7 for HE 0900 was $1,840.54, greater than the highest possible offer price of $1,800 per MWh.

Following the implementation of shortage pricing, generator offers remained capped at $1,000 per MWh but demand response offers were capped at $1,800 for the period between June 1, 2013, and May 31, 2014. The $1,800 is equal to the generator offer cap plus the sum of the applicable penalty factors ($800 per MWh) for synchronized reserves and non-synchronized primary reserves. This means that the highest possible SMP is $1,800 in the period between June 1, 2013, and May 31, 2014 unless there are emergency purchases on the margins with higher prices. SMP did exceed $1,800

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per MWh in some intervals in which there were no emergency purchases.

Participant behavior during cold weather days in January

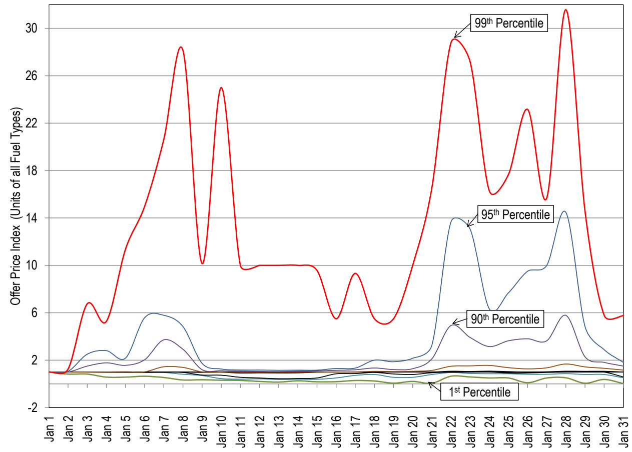
The high-demand days in January resulted in higher fuel costs and therefore in higher offer prices for gas fired units. That is expected behavior in a competitive market. However, some coal units also increased their offer prices significantly, including offers at $1,000 per MWh, in anticipation that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

Figure 3-45 shows the distribution of change in cleared offer prices at generating units' economic minimum output level in the month of January. The offer price index is the ratio of a unit's offer at its economic minimum on the specified day to its offer at its economic minimum on January 1, 2014.[100] For example, if a unit offered its economic minimum output at $50 per MWh on January 1, and offered its economic minimum output at $100 per MWh on January 7, the unit's offer price index for January 7 is calculated as 2.0. Figure 3-45 shows the daily percentiles of the offer price index plotted as smooth continuous curves.

Figure 3-45 shows that a substantial number of committed units had increased their offers, particularly for the forecasted cold days in January. On January 8, among committed units, ten percent of units had increased their offers to 3.0 times the offer level on January 1, five percent of units had increased their offers to 4.8 times the level offered on January 1, and one percent of units had increased their offers to 28.0 times the offer level on January 1.

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

Figure 3-45 Distributions of Offer Prices, All Units: January 2014



Most of the increased offer prices were from generators using natural gas facing very high fuel prices. Figure 3-46 shows the behavior of gas fired units in January. For example, on January 22, among committed natural gas units, 10 percent had increased their offers to 13 times the offer level on January 1, five percent had increased their offers to 19 times the offer level on January 1, and one percent had increased their offers to 28.0 times the offer level on January 1.

Figure 3-46 Distributions of Offer Prices, Gas Units: January 2014

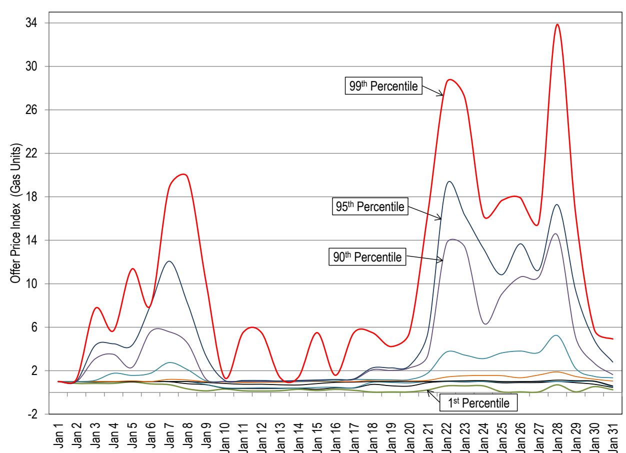
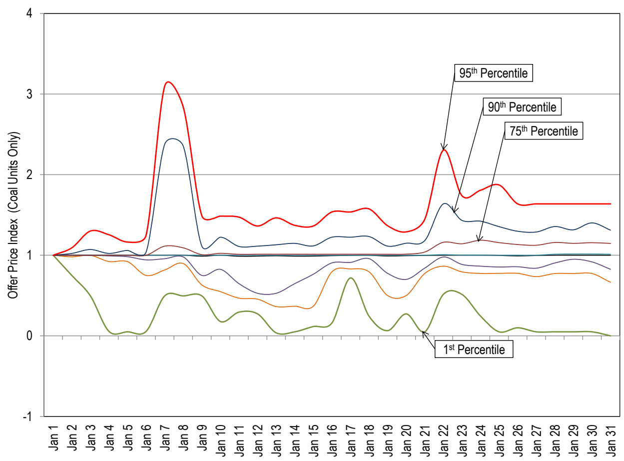


Figure 3-47 shows that a substantial number of coal units had also increased their offers for the forecasted cold days in January, although fuel costs do not explain these increases. For example, on January 8, among committed coal units, 10 percent had increased their offers to 2.3 times the offer level on January 1 and five percent had increased their offers to 3.0 times the offer level on January 1.

Figure 3-47 Distributions of Offer Prices, Coal Units: January 2014



Real-time markup on high demand days in January

Markup is calculated as the difference between the price-based offer and the cost-based offer of the marginal unit at its dispatched MW output. The MMU calculates the impact on system prices of marginal unit markup. The calculation shows the markup component of LMP based on the mark up of each actual marginal unit on the system.[101] Figure 3-48 shows the hourly markup component of PJM LMP for January. The markup component of real-time LMP was high on high-demand days in January 2014. For comparison, negative $3.12 per MWh or negative 8.3 percent of the PJM real-time load-weighted average LMP was attributable to markup in January 2013, whereas $6.51 per MWh or 5.1 percent of the PJM real-time load-weighted average LMP was attributable to markup in January 2014. This outcome is consistent with the hypothesis that some coal unit owners engaged in economic withholding by increasing markups in anticipation of high demand days on which they were likely to be dispatched.

Figure 3-48 Hourly Markup Component of PJM's System-wide Real-time LMP: January 2014

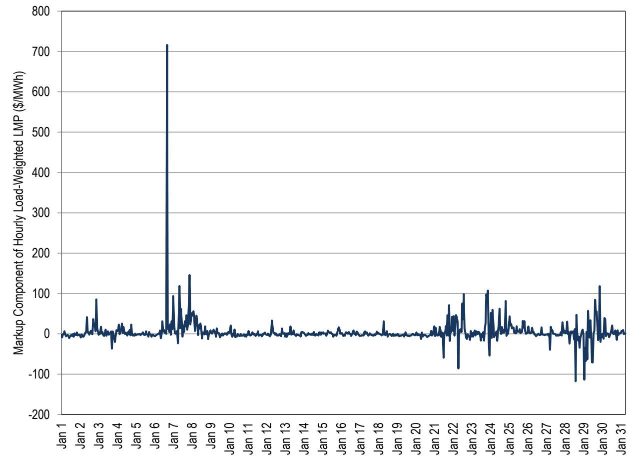
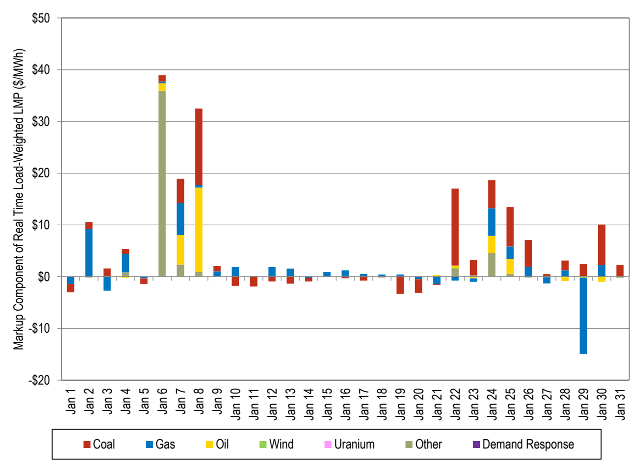


Figure 3-49 shows the markup component of PJM average daily real-time load-weighted LMP by fuel type. On many of the high demand days, coal units accounted for a substantial proportion of the markup component of PJM LMP. For example, on January 8, markup resulted in a $46 per MWh addition or 32 percent of the day's load-weighted LMP, of which coal units' markup accounted for $31per MWh or 21.8 percent of the day's load-weighted LMP.

Figure 3-49 Daily Markup Contribution to the Real-time Load-weighted LMP by Fuel Type: January



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

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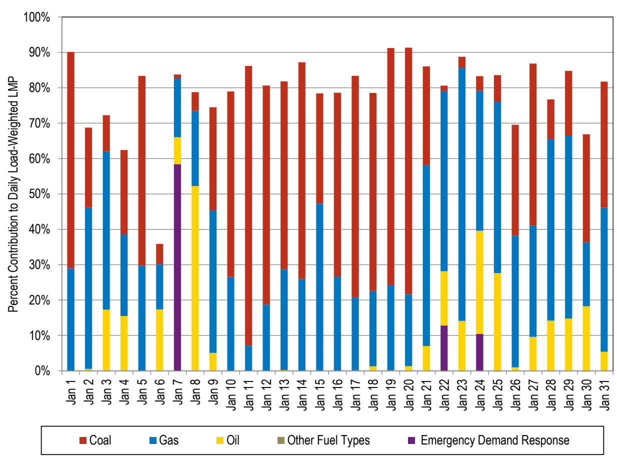
Marginal fuel

Figure 3-50 shows the contribution of a fuel cost and emergency demand response to the daily load-weighted LMP. On high-demand days in January, natural gas units contributed a larger share relative to the coal units to the PJM system-wide load weighted LMP. Even though natural gas units had a higher contribution to the load-weighted LMP than coal units, their markup contribution was not higher than that of coal units during those high-demand days. The expensive offers from natural gas units were primarily due to high fuel costs in contrast to coal units, which did not face the same level of fuel-price volatility as natural gas units in January.

Figure 3-50 Percentage Contribution of Fuel Cost to Daily Load-weighted Real Time LMP: January 2014



Capacity Resource Obligations

The conditions in January highlighted the inadequacy of the RPM performance incentives for generation resources and the implications of using demand side resources to replace generation in capacity auctions. In January 2014, demand resources were limited DR and were not required to be available during the winter. The displacement of existing and planned generation in capacity auctions by demand resources clearly contributed to the supply adequacy issues in January. Although a substantial portion of demand side resources did perform voluntarily, the effective outage rate for demand resources as a whole, comparing actual performance to total installed DR, far exceeded the forced outage rates for generating units. Single-fuel gas fired generators do not face performance penalties for lack of fuel outages in the winter. Some generators took lack of fuel forced outages for economic reasons when they were concerned about the risks associated with procuring gas.

Capacity resources should have uniform availability requirements. Outages and flexibility parameters should be based on the physical limitations at a unit and not based on economic decisions by resource owners. Cost based offers in the PJM energy market should also reflect the actual cost of fuel. The criteria for designating capacity as maximum emergency should be clearly defined and should apply at all times.[102]

The performance incentives for capacity resources need to be substantially strengthened as the high level of outages of capacity resources during January demonstrates. One specific incentive issue stands out based on the January experience. There is a provision in the PJM tariff that allows single-fueled, natural gas fired units to exclude outages during the winter peak hour period when the outage is for lack of fuel from the calculation of the peak period Equivalent Forced Outage Rate (EFORp) which directly affects the revenue received by capacity resources.[103] As a result of this exception, a participant that produces power by procuring gas and/or a backup fuel during the winter peak period and a participant that chooses to report a lack of fuel outage and produces no energy during the winter peak period are treated as if they performed identically although the participant not purchasing fuel is avoiding risk and not providing reliability. If the capacity payment is not reduced when a unit is unavailable during the winter peak period, there is no incentive for single-fueled natural gas fired units to procure gas during winter peak periods. That is the obligation of capacity resources that are paid the capacity market clearing price.

Interchange transactions

On January 7, 2014, at 0630, as part of the PJM/VACAR reserve sharing agreement, Progress Energy Carolinas (PEC) requested 200 MW of shared reserves from PJM on behalf of South Carolina Energy and Gas (SCE&G)

102 The MMU notes that PJM has taken a number of initiatives in the energy market targeting improved resource performance during winter months in various stakeholder forums. PJM has also filed a proposal to overhaul the RPM design to attempt to fix capacity incentives and performance obligations.

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

due to the loss of a 600 MW unit. PJM activated the shared reserves. At 0715, PJM informed PEC that they would need to recall the shared reserves, and at 0730, the shared reserve event ended. SCE&G shed 100 MW of load to maintain generation/load balance. At approximately 0815, PEC again requested 200 MW of shared reserves from PJM on behalf of SCE&G. As a result of the loss of generation and a synchronized reserve event, PJM was only able to provide the 200 MW of reserve sharing for 10 minutes, and recalled the 200 MW at 0825. At approximately 0830, SCE&G shed an additional 200 MW of load. At 0845, PJM provided 200 MW of shared reserves for SCE&G and an additional 200 MW for PEC. The 200 MW reserves provided to PEC ended at 1030 and the 200 MW of reserves provided for SCE&G ended at 2130.

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

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

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

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