Energy Market

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for the first nine months of 2015, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM energy market results were competitive in the first nine months of 2015.

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 the first nine months of 2015 was moderately concentrated. Average HHI was 1095 with a minimum of 879 and a maximum of 1468 in the first nine months of 2015.
- 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

1 Analysis of 2015 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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basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM energy market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[3] There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are extremely tight. If market-based offer caps are raised, or if generators are allowed to modify offers hourly, 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 12,877 MW, or 7.5 percent, in the summer months of 2015 from an average maximum of 171,602 MW to 158,724 MW. This decrease was a result of net unit retirements between October 1, 2014, and September 30, 2015 and unit outages. Between October 1, 2014, and September 30, 2015, 3,041.2 MW of new capacity were added to PJM and 10,476.9 MW of generation retired (11 units).

  PJM average real-time generation in the first nine months of 2015 decreased by 0.6 percent from the first nine months of 2014, from 92,449 MW to 91,901 MW.

  PJM average day-ahead supply in the first nine months of 2015, including INCs and up to congestion transactions, decreased by 27.4 percent from the first nine months of 2014, from 161,137 MW to 116,975 MW.

- **Market Concentration.** PJM energy market was moderately concentrated overall with moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.

- **Generation Fuel Mix.** During the first nine months of 2015, coal units provided 38.5 percent, nuclear units 34.3 percent and gas units 23.0 percent of total generation. Compared to the first nine months of 2014, generation from coal units decreased 13.6 percent, generation from gas units increased 29.4 percent and generation from nuclear units increased 1.1 percent.

- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first nine months of 2015, coal units were 54.46 percent of marginal resources and natural gas units were 34.88 percent of marginal resources. In the first nine months of 2014, coal units were 49.71 percent and natural gas units were 42.48 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market in the first nine months of 2015, up to congestion transactions were 76.5 percent of marginal resources, INCs were 4.9 percent of marginal resources, DECs were 8.6 percent of marginal resources, and generation resources were 11.5 percent of marginal resources. In the first nine months of 2014, up to congestion transactions were 93.7 percent of marginal resources, INCs were 1.6 percent of marginal resources, DECs were 2.2 percent of marginal resources, and generation resources were 2.4 percent of marginal resources.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM system peak load during the first nine months of 2015 was 143,697 MW in the HE 1700 on July 28, 2015, which was 2,023 MW, or 1.4 percent, higher than the PJM peak load for the first nine months of 2014, which was 141,673 MW in the HE 1700 on June 17, 2014.

  PJM average real-time load in the first nine months of 2015 increased by 1.4 percent from the first nine months of 2014, from 90,567 MW to 91,857 MW. PJM average day-ahead demand in the first nine months of 2015, including DECs and up to congestion transactions, decreased by

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.

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27.5 percent from the first nine months of 2014, from 156,542 MW to 113,553 MW.

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot market purchases. For the first nine months of 2015, 11.7 percent of real-time load was supplied by bilateral contracts, 29.2 percent by spot market purchases and 59.1 percent by self-supply. Compared with the first nine months of 2014, reliance on bilateral contracts increased by 1.1 percent, reliance on spot market purchases increased by 2.5 percentage points and reliance on self-supply decreased by 3.6 percentage points.
- **Supply and Demand: Scarcity.** There were no shortage pricing events in the first nine months of 2015.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours remained at 0.2 percent in the first nine months of 2014 and 2015. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 0.5 percent in the first nine months of 2014 to 0.4 percent in the first nine months of 2015.

  In the first nine months of 2015, 15 control zones experienced congestion resulting from one or more constraints binding for 75 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.
- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0.3 percent in the first nine months of 2014 to 0.5 percent in the first nine months of 2015. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0.3 percent in the first nine months of 2014 to 0.5 percent in the first nine months of 2015.
- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the PJM Real-Time Energy Market, when using unadjusted cost offers, in the first nine months of 2015, 85.7 percent of marginal units had average dollar markups less than zero and had an average markup index less than or equal to zero. Using adjusted cost offers, in the first nine months of 2015, 41.4 percent of marginal units had average dollar markups less than zero and average markup index less than or equal to zero. In the first nine months of 2015, using unadjusted cost offers, 6.7 percent of units had offer prices greater than $150 with average unadjusted dollar markup of $12.83. In the first nine months of 2014, 8.9 percent of units had offer prices greater than $150 with average unadjusted dollar markup of $22.17.

  In the PJM Day-Ahead Energy Market, when using unadjusted cost offers, in the first nine months of 2015, 40.3 percent of marginal generating units had an average markup index less than or equal to zero. Using adjusted cost offers, in the first nine months of 2015, 2.2 percent of marginal units had an average markup index less than or equal to zero. In the first nine months of 2015, using unadjusted cost offers, 3.3 percent of units had offer prices greater than or equal to $150 with average dollar markup of $4.39. In the first nine months of 2014, using unadjusted cost offers, 2.5 percent of units offer prices greater than or equal to $150 with average dollar markup of $13.94.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** 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. 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

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during the first 11 months of 2014, to zero in December 2014, and zero in the first nine months of 2015.

- **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. The reduction in up to congestion transactions (UTC) continued, following a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[4]

- **Generator Offers.** Generator offers are categorized as dispatchable and self scheduled. Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are categorized as self scheduled must run. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are categorized as self scheduled and dispatchable. Of all generator offers in the first nine months of 2015, 51.1 percent were offered as available for economic dispatch, 23.4 percent were offered as self scheduled, and 21.1 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 Energy Market prices decreased in the first nine months of 2015 compared to the first nine months of 2014. The load-weighted average real-time LMP was 33.5 percent lower in the first nine months of 2015 than in the first nine months of 2014, $38.94 per MWh versus $58.60 per MWh.

  PJM Day-Ahead Energy Market prices decreased in the first nine months of 2015 compared to the first nine months of 2014. The load-weighted average day-ahead LMP was 33.1 percent lower in the first nine months of 2015 than in the first nine months of 2014, $39.51 per MWh versus $59.09 per MWh.[5]

- **Components of LMP.** In the PJM Real-Time Energy Market, for the first nine months of 2015, 41.2 percent of the load-weighted LMP was the result of coal costs, 28.7 percent was the result of gas costs and 2.31 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market for the first nine months of 2015, 28.7 percent of the load-weighted LMP was the result of the cost of coal, 14.6 percent was the result of the cost of gas, 4.6 percent was the result of the up to congestion transactions, 22.3 percent was the result of DECs and 11.5 percent was the result of INCs.

- **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 the first nine months of 2015, the adjusted markup component of LMP was $1.75 per MWh or 4.5 percent of the PJM real-time, load-weighted average LMP. The month of February had the highest adjusted markup component, $6.44 per MWh, or 12.65 percent of the real-time load-weighted average LMP. In the first nine months of 2014, the adjusted markup was $3.61 per MWh or 6.2 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 the first nine months of 2015, the adjusted markup component of LMP resulting from generation resources was $0.81 per MWh or 2.1 percent of the PJM day-ahead load-weighted average LMP.

  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 the Day-Ahead and Real-Time Energy Markets, although the behavior of some participants during the high

4 148 FERC ¶ 61,144 (2014).

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

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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 the average day-ahead and real-time prices was -$1.04 per MWh in the first nine months of 2014 and -$0.70 per MWh in the first nine months of 2015. 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

- There were no shortage pricing events in the first nine months of 2015.

Recommendations

- The MMU recommends that the rules governing the application of the TPS test be clarified and documented, that markup be constant across price and cost offers, that there be at least one cost based offer using the same fuel as the available price based offer and that the parameters of the cost based offer be at least as flexible as the parameters of the available price based offer. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends the elimination of FMU and AU adders. Since the implementation of FMU adders, PJM has undertaken major redesigns of its market rules 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.[6]
- 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 PJM remove non-specific fuel types such as "other" or "co-fire other" from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules. The MMU recommends that PJM require every market participant to make available at least one cost schedule with the same fuel-type and parameters as that of their offered price schedule. (Priority: Medium. First reported Q2, 2015. Status: Not adopted.)
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[7] (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM not use closed loop interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product or for any other reason. (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

6 149 FERC ¶ 61,091 (2014).

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

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clarified, that PJM's role be strengthened and that the process be made transparent. (Priority: Low. First reported 2013. Status: Not adopted.)

- There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[8] 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.[9] (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 and price-based offers above the $1,000/MWh energy offer cap if both offer types 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. First reported 2014. Status: Partially adopted. Pending before FERC.)
- 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.)

8 The general definition of a hub can be found in PJM. "Manual 35: Definitions and Acronyms," Revision 23 (April 11, 2014).

9 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 the first nine months of 2015, 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 12,877 MW in the summer months of 2015 compared to the summer months of 2014, while peak load increased by 2,023 MW. Market concentration levels remained moderate although there is high concentration in the intermediate and peaking segments of the supply curve which adds to concerns about market power when market conditions are tight. The 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 although the market structure during high demand hours remains a concern.

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 the first nine months of 2015 generally reflected supply-demand fundamentals, although the behavior of some participants during high demand periods raises concerns about economic withholding. These

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

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[10] 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 for most hours to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive. However, there are some issues with the application of the TPS test in the Day-Ahead Energy Market. There is no tariff or manual language that defines in detail the application of the TPS test in the Day-Ahead Energy Market. In both the Day-Ahead and Real-Time Energy Markets, generators have the ability to avoid mitigation by using varying markups in their price based offers, offering different operating parameters in their price based and cost based offers, and using different fuels in their price based and cost based offers. These issues can be solved by simple rule changes.

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

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

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 and provide a reason to use cost as the sole basis for hourly changes in offers or offers greater than $1,000 per MWh. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2015.

Market Structure

Market Concentration

Analyses of supply curve segments of the PJM energy market in the first nine months of 2015 indicates moderate concentration in the base load segment, but high concentration in the intermediate and peaking segments.[11] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal during high demand periods.

When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall energy market. PJM offer-capping rules that limit the exercise of local market power were generally effective in preventing the exercise of market power in these areas during the first nine months of 2015.

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.[12]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM energy market during the first nine months of 2015 was moderately concentrated (Table 3-2).

Table 3-2 PJM hourly energy market HHI: January through September 2014 and 2015[13]

	Hourly Market HHI (Jan - Sep, 2014)	Hourly Market HHI (Jan - Sep, 2015)
Average	1154	1095
Minimum	930	879
Maximum	1468	1468
Highest market share (One hour)	29%	30%
Average of the highest hourly market share	21%	20%
# Hours	6,551	6,551
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-3 includes HHI values by supply curve segment, including base, intermediate and peaking plants for the first nine months of 2014 and 2015.

11 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.

12 77 FERC ¶ 61,263, pp. 64-70 (1996), "*Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement.*"

13 This analysis includes all hours in the first nine months of 2014 and 2015, regardless of congestion.

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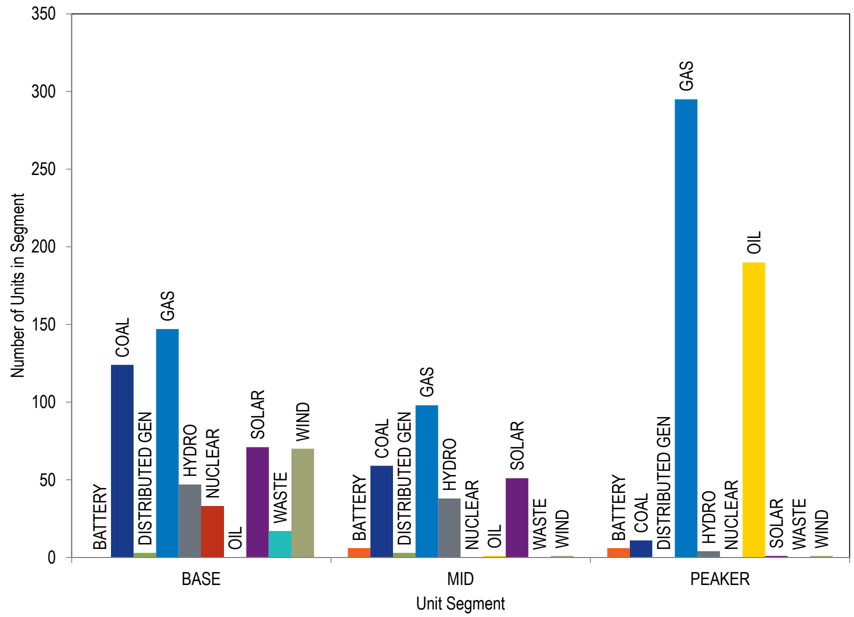
Table 3-3 PJM hourly energy market HHI (By supply segment): January through September 2014 and 2015

	Jan - Sep, 2014			Jan - Sep, 2015		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	1038	1181	1484	991	1124	1474
Intermediate	771	1914	6533	605	2014	6809
Peak	702	5940	10000	741	6111	10000

Figure 3-1 shows the number of units in the baseload, intermediate and peaking segments by fuel source in the first nine months of 2015.

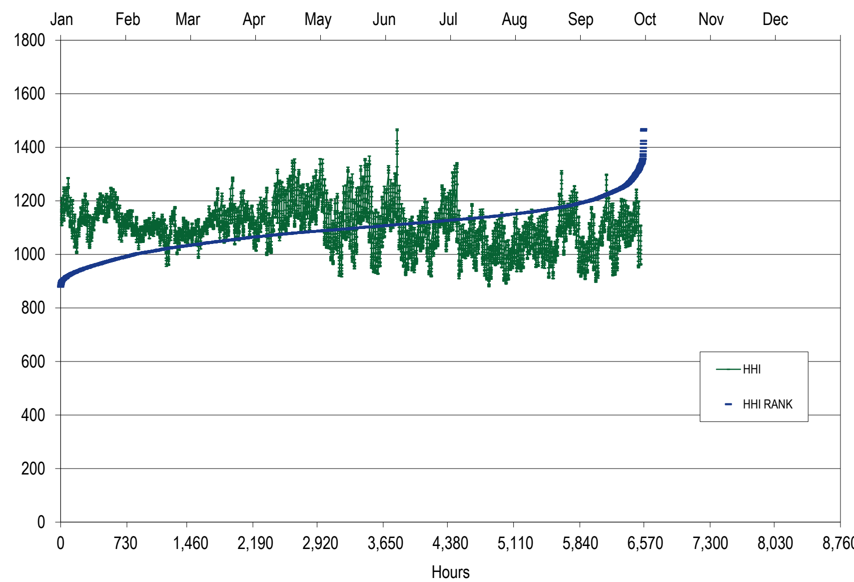
Figure 3-1 Fuel source distribution in unit segments: January through September 2015[14]



14 The units classified as Distributed Gen are buses within Electric Distribution Companies (EDCs) that are modeled as generation buses to accurately reflect net energy injections from distribution level load buses. The modeling change was the outcome of the Net Energy Metering Task Force stakeholder group in July, 2012.

Figure 3-2 presents the hourly HHI values in chronological order and an HHI duration curve for the first nine months of 2015.

Figure 3-2 PJM hourly energy market HHI: January through September 2015



Ownership of Marginal Resources

Table 3-4 shows the contribution to real-time, load-weighted LMP by individual marginal resource owner.[15] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of 2015, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. The results show that in the first nine months of 2015, the offers of one company contributed 18.6 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 54.8 percent of the real-time, load-weighted, average PJM system LMP. During the first nine months of 2014, the offers of one company contributed 17.8 percent of the real time, load-weighted PJM system

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

LMP and offers of the top four companies contributed 55.3 percent of the real-time, load-weighted, average PJM system LMP.

Table 3-4 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): January through September 2014 and 2015

2014 (Jan-Sep)		2015 (Jan-Sep)	
Company	Percent of Price	Company	Percent of Price
1	17.8%	1	18.6%
2	16.2%	2	15.4%
3	12.2%	3	11.3%
4	9.1%	4	9.4%
5	7.6%	5	8.1%
6	6.2%	6	8.0%
7	5.5%	7	5.0%
8	5.3%	8	4.5%
9	3.7%	9	2.9%
Other (60 companies)	16.4%	Other (58 companies)	16.8%

Table 3-5 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[16] 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 (10.5 percent), in the first nine months of 2014 also had the largest impact (16.7 percent) in the first nine months of 2015.

Table 3-5 Marginal resource contribution to PJM day-ahead, load-weighted LMP (By parent company): January through September of 2014 and 2015

2014 (Jan - Sep)		2015 (Jan - Sep)	
Company	Percent of Price	Company	Percent of Price
1	10.5%	1	16.7%
2	8.1%	2	10.0%
3	6.6%	3	8.8%
4	5.6%	4	5.5%
5	5.6%	5	4.9%
6	5.4%	6	4.8%
7	4.7%	7	4.1%
8	3.6%	8	4.0%
9	3.0%	9	3.2%
Other (144 companies)	46.9%	Other (149 companies)	38.0%

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

Type of Marginal Resources

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

Table 3-6 shows the type of fuel used by marginal resources in the Real-Time Energy Market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first nine months of 2015, coal units were 54.46 percent and natural gas units were 34.88 percent of marginal resources. In the first nine months of 2014, coal units were 49.71 percent and natural gas units were 42.48 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.[17] In the first nine months of 2015, 70.29 percent of the wind marginal units had negative offer prices, 25.87 percent had zero offer prices and 3.84 percent had positive offer prices.

17 Prior to April 1, 2015, for the generation units that are capable of using multiple fuel types, PJM did 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): January through September 2011 through 2015

	Year (Jan-Sep)				
Type/Fuel	2011	2012	2013	2014	2015
Coal	68.84%	58.11%	57.56%	49.71%	54.46%
Gas	25.89%	30.82%	34.13%	42.48%	34.88%
Interface	0.24%	0.00%	0.00%	0.00%	0.00%
Oil	2.36%	6.04%	3.22%	3.44%	7.39%
Wind	1.97%	4.30%	4.75%	3.86%	2.74%
Other	0.00%	0.58%	0.21%	0.35%	0.43%
Municipal Waste	0.68%	0.14%	0.08%	0.04%	0.06%
Uranium	0.02%	0.01%	0.02%	0.06%	0.03%
Emergency DR	0.00%	0.00%	0.03%	0.05%	0.00%

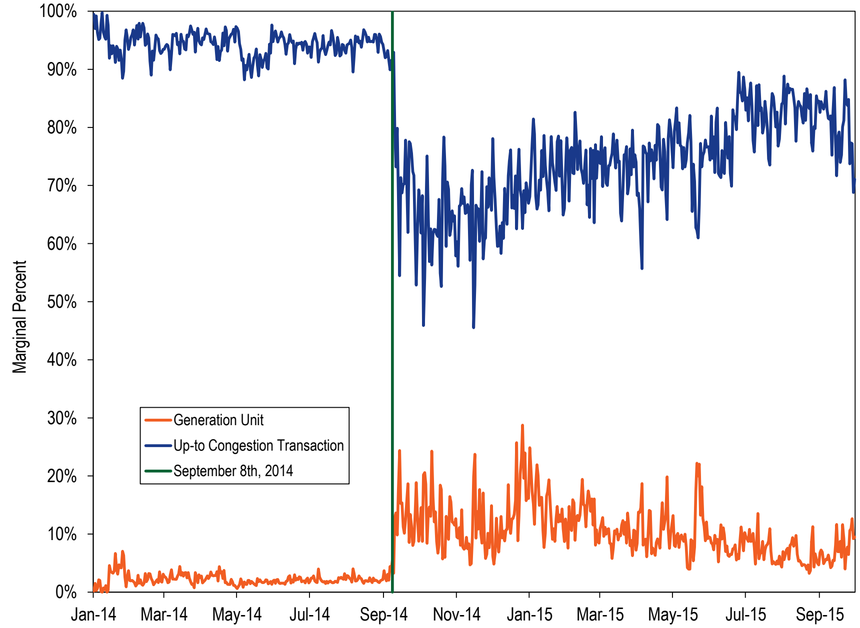
Table 3-7 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first nine months of 2015, up to congestion transactions were 76.47 percent of marginal resources. Up to congestion transactions were 93.69 percent of marginal resources in the first nine months of 2014.

Table 3-7 Day-ahead marginal resources by type/fuel: January through September of 2011 through 2015

	Year (Jan - Sep)				
Type/Fuel	2011	2012	2013	2014	2015
Up-to Congestion Transaction	69.42%	86.73%	96.23%	93.69%	76.47%
DEC	14.40%	5.15%	1.24%	2.19%	8.58%
Coal	5.36%	2.46%	0.97%	1.44%	6.04%
INC	8.44%	4.36%	1.01%	1.59%	4.94%
Gas	1.78%	1.12%	0.44%	0.95%	3.12%
Oil	0.00%	0.00%	0.00%	0.02%	0.33%
Dispatchable Transaction	0.24%	0.07%	0.06%	0.08%	0.31%
Wind	0.07%	0.04%	0.04%	0.03%	0.14%
Price Sensitive Demand	0.28%	0.05%	0.01%	0.01%	0.03%
Other	0.00%	0.00%	0.00%	0.00%	0.02%
Municipal Waste	0.01%	0.01%	0.00%	0.00%	0.01%
Total	100.00%	100.00%	100.00%	100.00%	100.00%

Figure 3-3 shows, for the Day-Ahead Market in 2014 through September of 2015, 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.[18] 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 through September of 2015



Supply

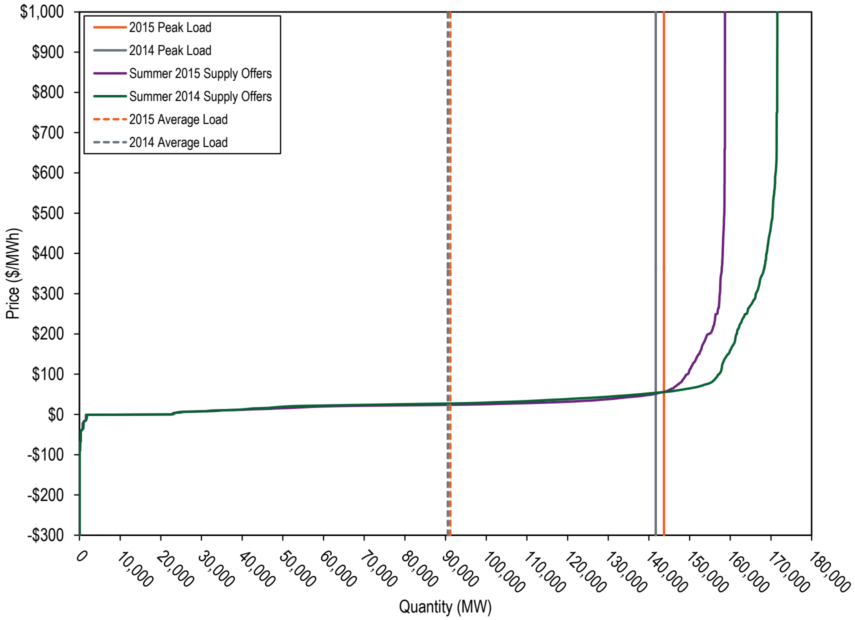
Supply includes physical generation and imports and virtual transactions.

Figure 3-4 shows the average PJM aggregate real-time generation supply curves by offer price, peak load and average load for the summer of 2014 and 2015. Total average PJM aggregate real-time generation supply decreased by

18 See 18 CFR § 385.213 (2014).

12,877 MW, or 7.5 percent, in the summer of 2015 from an average maximum of 171,602 MW to 158,724 MW in the summer of 2015.

Figure 3-4 Average PJM aggregate real-time generation supply curves by offer price: Summer of 2014 and 2015



Energy Production by Fuel Source

In the first nine months of 2015, generation from coal units decreased 13.6 percent and generation from natural gas units increased 29.9 percent compared to the first nine months of 2014 (Table 3-8).[19]

Table 3-8 PJM generation (By fuel source (GWh)): January through September of 2014 and 2015[20]

	Jan-Sep 2014		Jan-Sep 2015		Change in
	GWh	Percent	GWh	Percent	Output
Coal	272,056.5	44.2%	234,932.4	38.5%	(13.6%)
Standard Coal	269,080.8	43.8%	232,466.8	38.1%	(13.6%)
Waste Coal	2,975.7	0.5%	2,465.6	0.4%	(17.1%)
Nuclear	207,170.7	33.7%	209,378.1	34.3%	1.1%
Gas	108,363.6	17.6%	140,203.5	23.0%	29.4%
Natural Gas	105,635.4	17.2%	137,271.8	22.5%	29.9%
Landfill Gas	1,786.6	0.3%	1,815.8	0.3%	1.6%
Biomass Gas	941.6	0.2%	1,115.9	0.2%	18.5%
Hydroelectric	11,601.1	1.9%	10,073.2	1.7%	(13.2%)
Pumped Storage	5,742.0	0.9%	4,910.1	0.8%	(14.5%)
Run of River	5,859.0	1.0%	5,163.1	0.8%	(11.9%)
Wind	10,723.0	1.7%	10,792.7	1.8%	0.7%
Waste	3,628.3	0.6%	3,480.4	0.6%	(4.1%)
Solid Waste	3,165.8	0.5%	3,071.6	0.5%	(3.0%)
Miscellaneous	462.5	0.1%	408.8	0.1%	(11.6%)
Oil	983.9	0.2%	845.9	0.1%	(14.0%)
Heavy Oil	464.1	0.1%	609.5	0.1%	31.3%
Light Oil	424.5	0.1%	179.9	0.0%	(57.6%)
Diesel	74.1	0.0%	54.7	0.0%	(26.2%)
Kerosene	21.2	0.0%	1.8	0.0%	(91.7%)
Jet Oil	0.0	0.0%	0.0	0.0%	NA
Solar, Net Energy Metering	330.7	0.0%	436.8	0.0%	32.1%
Battery	5.8	0.0%	4.5	0.0%	(21.3%)
Total	614,863.5	100.0%	610,147.6	100.0%	(0.8%)

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

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

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Table 3-9 Monthly PJM generation (By fuel source (GWh)): January through September 2015

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Coal	32,666.4	33,315.4	25,902.0	18,265.1	21,619.0	24,258.9	27,534.0	26,910.5	24,461.1	234,932.4
Standard Coal	32,309.5	32,992.8	25,589.6	18,068.7	21,363.2	24,000.4	27,330.1	26,618.6	24,193.8	232,466.8
Waste Coal	356.8	322.6	312.4	196.4	255.8	258.5	203.8	291.9	267.3	2,465.6
Nuclear	25,881.8	21,994.5	22,290.8	20,346.7	22,641.7	23,823.5	24,119.1	24,889.5	23,390.5	209,378.1
Gas	13,911.6	13,267.0	14,462.9	12,115.7	14,289.8	16,629.6	20,057.0	18,852.0	16,618.1	140,203.5
Natural Gas	13,567.7	12,957.9	14,155.0	11,840.9	13,978.2	16,281.6	19,690.6	18,495.6	16,304.3	137,271.8
Landfill Gas	213.5	188.1	208.4	200.0	212.1	196.1	208.0	201.6	187.9	1,815.8
Biomass Gas	130.4	121.0	99.5	74.7	99.5	151.9	158.3	154.8	125.9	1,115.9
Hydroelectric	953.9	763.3	1,152.3	1,379.6	1,025.2	1,310.5	1,624.2	1,105.5	758.8	10,073.2
Pumped Storage	398.8	388.7	344.7	331.4	504.2	729.1	842.9	823.6	546.7	4,910.1
Run of River	555.1	374.6	807.6	1,048.2	521.0	581.4	781.3	281.9	212.0	5,163.1
Wind	1,664.4	1,511.1	1,701.2	1,642.0	1,209.1	955.2	639.4	623.9	846.5	10,792.7
Waste	400.9	324.0	357.1	378.6	384.8	407.5	412.9	430.7	383.9	3,480.4
Solid Waste	347.8	279.7	308.0	335.4	347.2	370.7	369.8	380.9	332.1	3,071.6
Miscellaneous	53.1	44.3	49.1	43.2	37.5	36.8	43.2	49.8	51.8	408.8
Oil	81.0	408.6	13.1	5.3	43.8	45.7	158.0	69.9	26.7	851.9
Heavy Oil	64.3	315.0	0.0	0.0	0.0	29.3	143.3	57.6	0.0	609.5
Light Oil	13.7	58.8	10.3	5.2	40.0	12.6	11.9	8.6	18.9	179.9
Diesel	2.9	33.4	2.5	0.2	3.8	3.8	1.8	1.6	4.8	54.7
Kerosene	0.1	1.4	0.2	0.0	0.0	0.0	0.0	0.0	0.0	1.8
Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	1.0	2.0	3.0	6.0
Solar	23.0	31.8	38.2	52.5	60.9	52.3	60.5	62.1	49.7	431.0
Battery	0.4	0.4	0.5	0.4	0.5	0.6	0.6	0.5	0.8	4.5
Net Energy Metering	0.3	0.3	0.4	0.6	1.0	0.6	0.7	1.0	0.7	5.8
Total	75,583.7	71,616.3	65,918.5	54,186.4	61,275.7	67,484.5	74,606.4	72,945.6	66,536.7	610,153.6

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 12,877 MW, or 7.5 percent, in the summer months of 2015 from an average maximum of 171,602 MW to 158,724 MW.[21] This decrease was a result of net unit retirements between October 1, 2014, and September 30, 2015 and unit outages. Between October 1, 2014, and September 30, 2015, 3,041.2 MW of new capacity were added to PJM and 10,476.9 MW of generation retired (11 units).

PJM average real-time generation in the first nine months of 2015 decreased by 0.6 percent from the first nine months of 2014, from 92,449 MW to 91,901 MW.[22]

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

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

PJM average real-time supply including imports decreased by 0.0 percent in the first nine months of 2015 from the first nine months of 2014, from 97,992 MW to 97,896 MW.

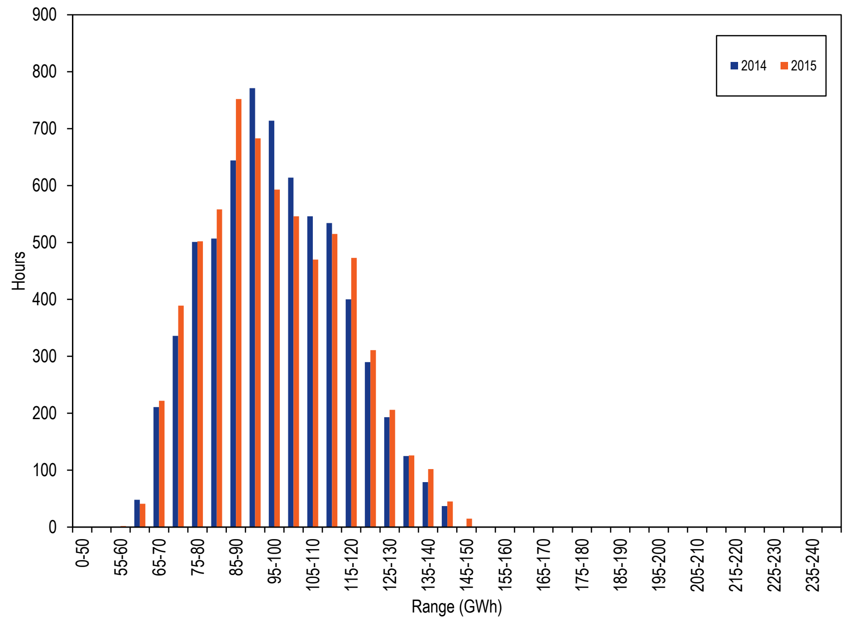
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **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 the first nine months of 2014 and 2015.

Figure 3-5 Distribution of PJM real-time generation plus imports: January through September of 2014 and 2015[23]



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

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PJM Real-Time, Average Supply

Table 3-10 presents summary real-time supply statistics for each year for the first nine months of the 16-year period from 2000 through 2015.[24]

Table 3-10 PJM real-time average hourly generation and real-time average hourly generation plus average hourly imports: January through September of 2000 through 2015

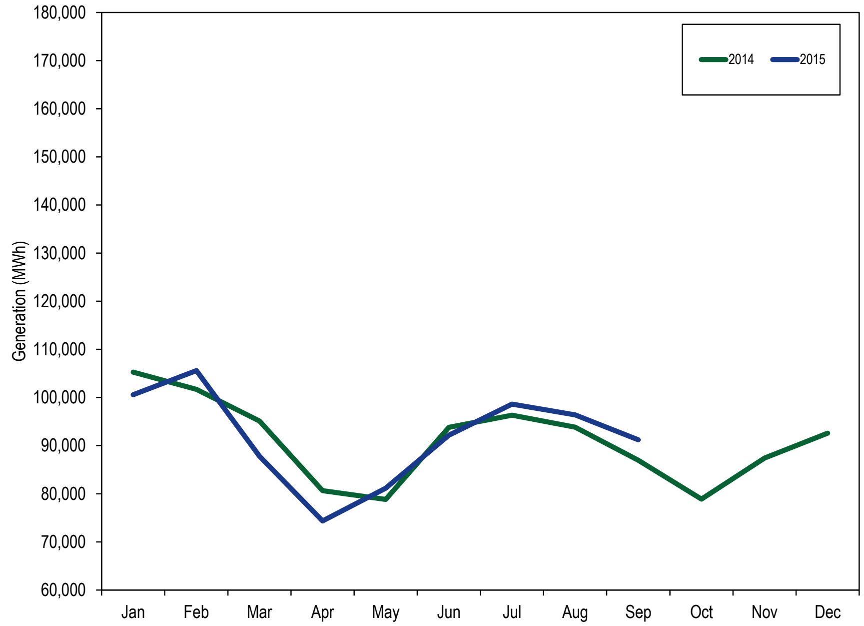
	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2000	30,989	5,216	33,855	5,966	NA	NA	NA	NA
2001	30,304	5,216	33,299	5,571	(2.2%)	0.0%	(1.6%)	(6.6%)
2002	34,467	8,217	38,207	8,540	13.7%	57.5%	14.7%	53.3%
2003	37,211	6,556	40,815	6,526	8.0%	(20.2%)	6.8%	(23.6%)
2004	45,888	11,035	49,990	11,185	23.3%	68.3%	22.5%	71.4%
2005	81,095	16,710	86,330	17,216	76.7%	51.4%	72.7%	53.9%
2006	84,260	14,696	88,621	15,399	3.9%	(12.1%)	2.7%	(10.5%)
2007	87,297	14,853	91,647	15,668	3.6%	1.1%	3.4%	1.7%
2008	85,241	14,203	90,621	14,646	(2.4%)	(4.4%)	(1.1%)	(6.5%)
2009	78,850	14,242	83,986	14,728	(7.5%)	0.3%	(7.3%)	0.6%
2010	84,086	16,346	88,876	17,001	6.6%	14.8%	5.8%	15.4%
2011	86,966	17,369	91,746	18,276	3.4%	6.3%	3.2%	7.5%
2012	90,367	16,893	95,726	17,810	3.9%	(2.7%)	4.3%	(2.5%)
2013	90,432	15,792	95,639	16,729	0.1%	(6.5%)	(0.1%)	(6.1%)
2014	92,449	16,002	97,922	17,064	2.2%	1.3%	2.4%	2.0%
2015	91,901	16,711	97,896	17,863	(0.6%)	4.4%	(0.0%)	4.7%

24 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 the first nine months of 2014 and 2015.

Figure 3-6 PJM real-time average monthly hourly generation: January 2014 through September 2015



Day-Ahead Supply

PJM average day-ahead supply in the first nine months of 2015, including INCs and up to congestion transactions, decreased by 27.4 percent from the first nine months of 2014, from 161,137 MW to 116,975 MW.

PJM average day-ahead supply in the first nine months of 2015, including INCs, up to congestion transactions, and imports, decreased by 27.0 percent from the first nine months of 2014, from 163,431 MW to 119,349 MW. The reduction in PJM day-ahead supply was a result of a sharp decrease in in

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UTCs beginning in September 2014 based on a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[25]

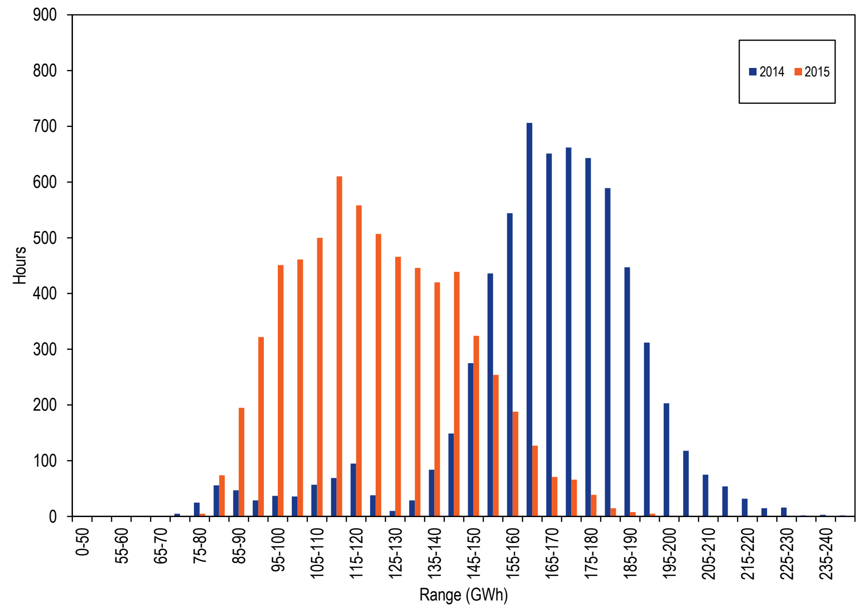
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **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 (UTC).** 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 the first nine months of 2014 and 2015. The shift in the results was a result of the sharp decrease in in UTCs beginning in September 2014.

Figure 3-7 Distribution of PJM day-ahead supply plus imports: January through September of 2014 and 2015[26]



25 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).

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

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PJM Day-Ahead, Average Supply

Table 3-11 presents summary day-ahead supply statistics for the first nine months of each year of the 16-year period from 2000 through 2015.[27]

Table 3-11 PJM day-ahead average hourly supply and day-ahead average hourly supply plus average hourly imports: January through September 2000 through 2015

	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	27,853	5,340	28,233	5,395	NA	NA	NA	NA
2001	27,519	4,839	28,279	4,911	(1.2%)	(9.4%)	0.2%	(9.0%)
2002	30,080	10,982	30,629	10,992	9.3%	126.9%	8.3%	123.8%
2003	40,024	9,079	40,556	9,066	33.1%	(17.3%)	32.4%	(17.5%)
2004	56,103	13,380	56,799	13,349	40.2%	47.4%	40.0%	47.2%
2005	94,437	18,671	96,315	18,963	68.3%	39.5%	69.6%	42.1%
2006	100,888	18,061	103,029	18,071	6.8%	(3.3%)	7.0%	(4.7%)
2007	110,300	17,561	112,575	17,752	9.3%	(2.8%)	9.3%	(1.8%)
2008	107,367	16,601	109,811	16,717	(2.7%)	(5.5%)	(2.5%)	(5.8%)
2009	98,527	17,462	101,123	17,526	(8.2%)	5.2%	(7.9%)	4.8%
2010	108,309	23,295	111,059	23,464	9.9%	33.4%	9.8%	33.9%
2011	116,988	22,722	119,488	23,015	8.0%	(2.5%)	7.6%	(1.9%)
2012	135,213	18,553	137,670	18,788	15.6%	(18.3%)	15.2%	(18.4%)
2013	148,489	18,858	150,785	19,073	9.8%	1.6%	9.5%	1.5%
2014	161,137	23,922	163,431	24,080	8.5%	26.9%	8.4%	26.2%
2015	116,975	20,289	119,349	20,502	(27.4%)	(15.2%)	(27.0%)	(14.9%)

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 the first nine months of 2014 and 2015. The reduction in PJM day-ahead supply was a result of a sharp decrease in in UTCs beginning in September 2014 based on a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[28]

Figure 3-8 PJM day-ahead monthly average hourly supply: January 2014 through September 2015

Real-Time and Day-Ahead Supply

Table 3-12 presents summary statistics for the first nine months of 2014 and 2015, for day-ahead and real-time supply. The last two columns of Table 3-12 are the day-ahead supply minus the real-time supply. The first of these columns is the total day-ahead supply less the total real-time supply and the second of these columns is the total physical day-ahead generation less the total physical real-time generation. In the first nine months of 2015 up-to congestion transactions were 15.1 percent of the total day-ahead supply compared to 38.2 percent in the first nine months of 2014.

27 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.

28 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).

Table 3-12 Day-ahead and real-time supply (MWh): January through September 2014 and 2015

		Day Ahead					Real Time		Day Ahead Less Real Time	
	(Jan-Sep)	Generation	INC Offers	Up-to Congestion	Imports	Total Supply	Generation	Total Supply	Total Supply	Total Generation
Average	2014	95,427	3,359	62,351	2,294	163,431	92,449	97,922	65,509	2,978
	2015	94,301	4,594	18,080	2,374	119,349	91,901	97,896	21,453	2,400
Median	2014	94,776	3,226	65,651	2,268	166,097	91,287	96,679	69,418	3,489
	2015	93,322	4,535	17,552	2,384	117,560	90,206	95,989	21,571	3,115
Standard Deviation	2014	16,852	881	17,350	428	24,080	16,002	17,064	7,016	849
	2015	17,925	763	4,519	487	20,502	16,711	17,863	2,639	1,214
Peak Average	2014	105,800	3,828	62,347	2,463	174,438	101,790	107,959	66,479	4,010
	2015	104,524	4,724	19,465	2,546	131,260	100,707	107,452	23,808	3,817
Peak Median	2014	105,384	3,816	66,186	2,406	177,198	101,266	107,135	70,063	4,119
	2015	104,631	4,689	18,687	2,577	130,053	100,827	106,981	23,072	3,804
Peak Standard Deviation	2014	13,485	800	16,853	389	21,930	13,183	14,063	7,868	302
	2015	14,345	721	4,646	477	17,376	14,479	15,285	2,090	(134)
Off-Peak Average	2014	86,357	2,948	62,355	2,147	153,806	84,281	89,146	64,660	2,076
	2015	85,004	4,475	16,821	2,217	108,517	83,893	89,206	19,311	1,111
Off-Peak Median	2014	85,081	2,851	65,234	2,107	157,517	82,531	87,177	70,340	2,549
	2015	82,558	4,398	16,375	2,204	105,109	81,572	86,201	18,908	986
Off-Peak Standard Deviation	2014	14,034	731	17,776	405	21,630	13,603	14,414	7,216	431
	2015	15,650	781	4,005	440	16,786	14,420	15,437	1,348	1,230

Figure 3-9 shows the average hourly cleared volumes of day-ahead supply and real-time supply for January through September of 2015. 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.

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Figure 3-9 Day-ahead and real-time supply (Average hourly volumes): January through September 2015

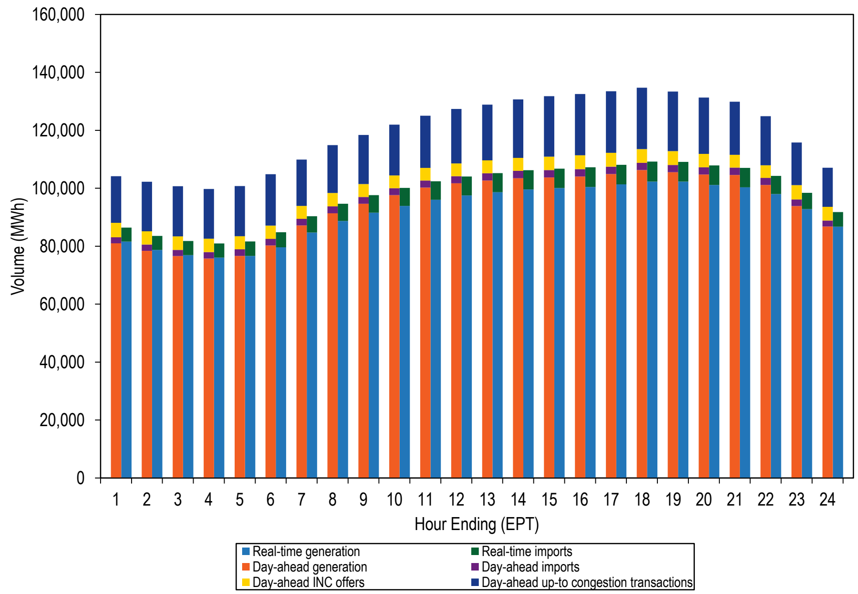

Figure 3-10 shows the difference between the day-ahead and real-time average daily supply in January 2014 through September 2015.

Figure 3-10 Difference between day-ahead and real-time supply (Average daily volumes): January 2014 through September 2015

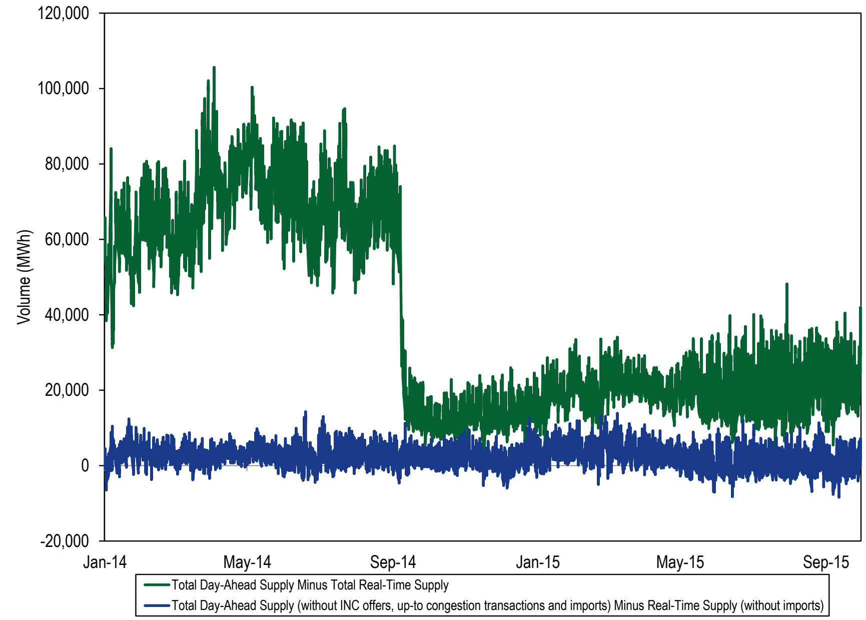

Figure 3-11 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2015. Table 3-13 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2014 and 2015. Figure 3-11 is color coded on a 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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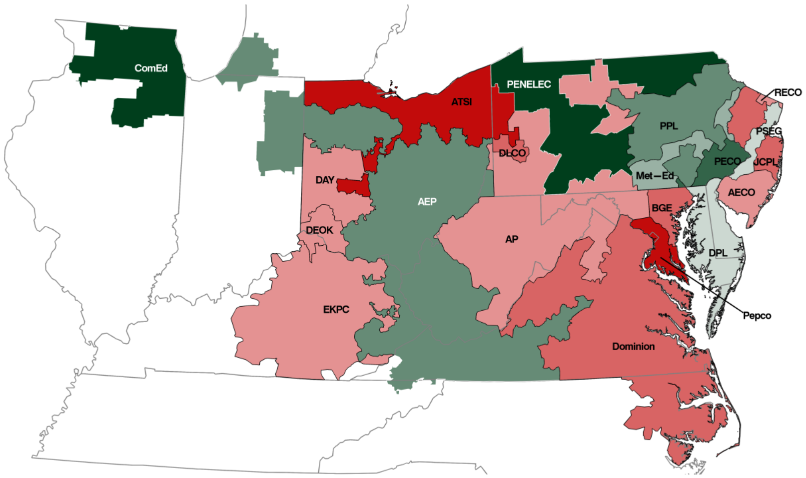
Figure 3-11 Map of PJM real-time generation less real-time load by zone: January through September 2015[29]



Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)
AECO	(3,608)	ComEd	21,540	DPL	(8,462)	PENELEC	17,357
AEP	10,612	DAY	(2,977)	EKPC	(2,652)	Pepco	(16,285)
AP	(3,635)	DEOK	(6,684)	JCPL	(7,600)	PPL	9,548
ATSI	(14,301)	DLCO	1,802	Met-Ed	5,405	PSEG	2,189
BGE	(8,009)	Dominion	(6,885)	PECO	14,138	RECO	(1,193)

Table 3-13 PJM real-time generation less real-time load by zone (GWh): January through September 2014 and 2015

	Zonal Generation and Load (GWh)					
	(Jan-Sep) 2014			(Jan-Sep) 2015		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	2,450.0	7,922.8	(5,472.8)	4,690.2	8,298.6	(3,608.4)
AEP	115,730.6	97,210.9	18,519.7	108,241.2	97,629.7	10,611.5
AP	34,345.1	36,376.7	(2,031.6)	33,549.1	37,184.4	(3,635.2)
ATSI	40,304.0	51,283.2	(10,979.2)	36,959.8	51,261.0	(14,301.2)
BGE	16,464.0	24,530.5	(8,066.5)	17,178.4	25,187.6	(8,009.2)
ComEd	94,155.0	74,455.2	19,699.8	94,908.9	73,368.4	21,540.5
DAY	11,122.1	12,881.1	(1,759.0)	9,997.4	12,974.4	(2,977.0)
DEOK	14,713.6	20,621.5	(5,907.9)	14,105.1	20,789.1	(6,684.0)
DLCO	13,073.4	11,031.7	2,041.8	12,825.5	11,023.9	1,801.6
Dominion	62,805.2	72,795.6	(9,990.4)	68,188.1	75,073.5	(6,885.4)
DPL	5,729.5	14,045.1	(8,315.6)	6,181.3	14,642.9	(8,461.6)
EKPC	8,030.0	9,624.9	(1,594.9)	6,778.9	9,431.4	(2,652.5)
JCPL	9,677.0	17,466.6	(7,789.6)	10,606.1	18,205.8	(7,599.6)
Met-Ed	16,395.7	11,460.4	4,935.4	17,155.5	11,750.7	5,404.7
PECO	45,657.6	30,380.1	15,277.4	45,623.0	31,485.0	14,138.1
PENELEC	34,448.5	12,962.8	21,485.8	30,415.3	13,058.6	17,356.7
Pepco	9,555.6	23,421.0	(13,865.5)	7,590.2	23,874.7	(16,284.5)
PPL	37,387.9	30,825.7	6,562.2	40,847.5	31,299.9	9,547.6
PSEG	33,586.9	32,857.8	729.1	36,200.4	34,011.9	2,188.5
RECO	0.0	1,148.2	(1,148.2)	0.0	1,193.4	(1,193.4)

Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

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

The PJM system real-time peak load for the first nine months of 2015 was 143,697 MW in the HE 1700 on July 28, 2015, which was 2,023 MW, or 1.4

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

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percent, higher than the peak load for the first nine months of 2014, which was 141,673 MW in the HE 17 on June 17, 2014.

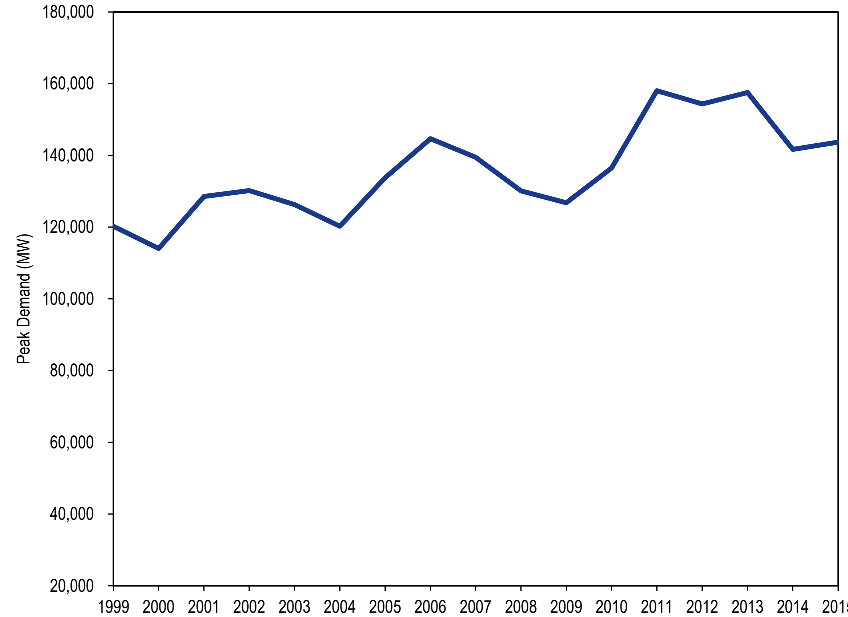
Table 3-14 shows the peak loads for the first nine months of 1999 through 2015.

Table 3-14 Actual PJM footprint peak loads: January through September 1999 to 2015[30]

(Jan - Sep)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Fri, July 30	17	120,227	NA	NA
2000	Wed, August 09	17	114,036	(6,191)	(5.1%)
2001	Wed, August 08	17	128,535	14,499	12.7%
2002	Thu, August 01	17	130,159	1,625	1.3%
2003	Thu, August 21	17	126,259	(3,900)	(3.0%)
2004	Wed, June 09	17	120,218	(6,041)	(4.8%)
2005	Tue, July 26	16	133,761	13,543	11.3%
2006	Wed, August 02	17	144,644	10,883	8.1%
2007	Wed, August 08	16	139,428	(5,216)	(3.6%)
2008	Mon, June 09	17	130,100	(9,328)	(6.7%)
2009	Mon, August 10	17	126,798	(3,302)	(2.5%)
2010	Tue, July 06	17	136,460	9,662	7.6%
2011	Thu, July 21	17	158,016	21,556	15.8%
2012	Tue, July 17	17	154,344	(3,672)	(2.3%)
2013	Thu, July 18	17	157,508	3,165	2.1%
2014	Tue, June 17	17	141,673	(15,835)	(10.1%)
2015	Tue, July 28	17	143,697	2,023	1.4%

Figure 3-12 shows the peak loads for the first nine months of 1999 through 2015.

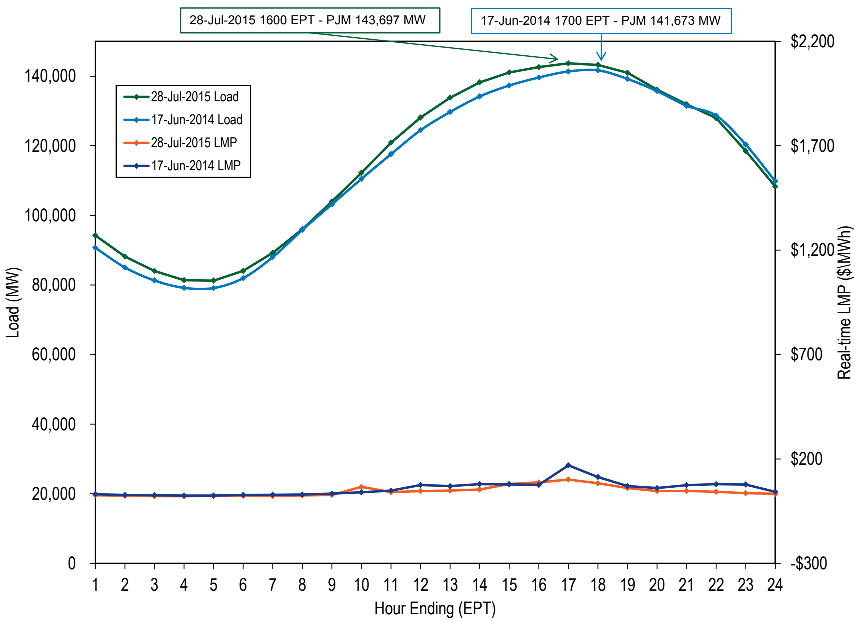
Figure 3-12 PJM footprint calendar year peak loads: January through September 1999 to 2015



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

Figure 3-13 compares the peak load days during the first nine months of 2014 and 2015. The average hourly real-time LMP peaked at $101.40 on July 28, 2015 and peaked at $169.33 on June 17, 2014.

Figure 3-13 PJM peak-load comparison: Tuesday, July 28, 2015, and Tuesday, June 17, 2014



Real-Time Demand

PJM average real-time load in the first nine months of 2015 increased by 1.4 percent from the first nine months of 2014, from 90,567 MW to 91,857 MW.[31]

PJM average real-time demand in the first nine months of 2015 increased 0.1 percent from the first nine months of 2014, from 96,015 MW to 96,102 MW.

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

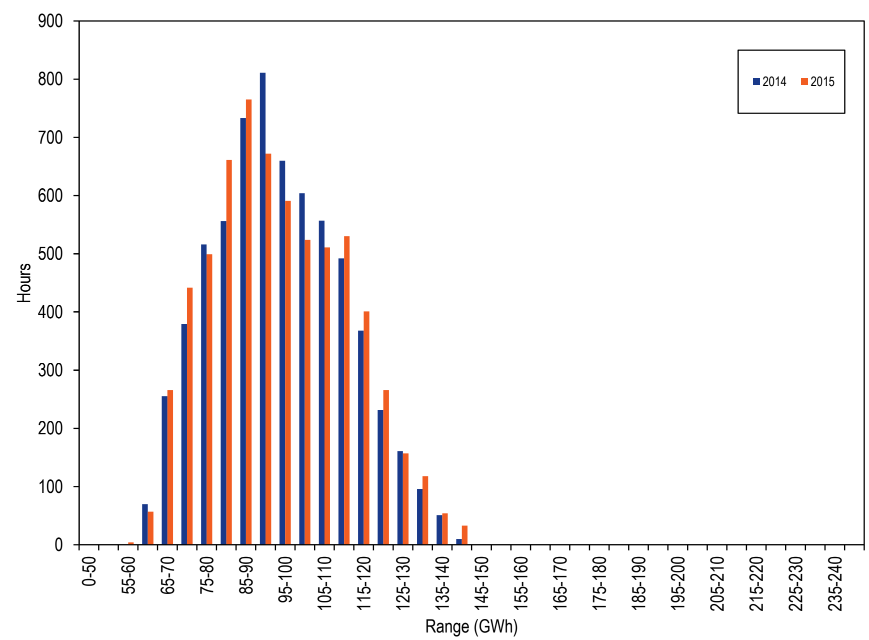
In the PJM Real-Time Energy Market, there are two types of demand:

- **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 the first nine months of 2014 and 2015.[32]

Figure 3-14 Distribution of PJM real-time accounting load plus exports: January through September 2014 and 2015[33]



32 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>.

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

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PJM Real-Time, Average Load

Table 3-15 presents summary real-time demand statistics for the first nine months during the 18-year period 1998 to 2054. 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.[34]

Table 3-15 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: January through September of 1998 through 2015[35]

	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	29,112	5,780	29,112	5,780	NA	NA	NA	NA
1999	30,236	6,306	30,236	6,306	3.9%	9.1%	3.9%	9.1%
2000	30,266	5,765	31,060	5,977	0.1%	(8.6%)	2.7%	(5.2%)
2001	31,060	6,156	32,900	5,861	2.6%	6.8%	5.9%	(2.0%)
2002	35,715	8,688	37,367	8,878	15.0%	41.1%	13.6%	51.5%
2003	37,996	7,187	39,965	7,120	6.4%	(17.3%)	7.0%	(19.8%)
2004	45,294	10,512	49,176	11,556	19.2%	46.3%	23.0%	62.3%
2005	78,235	17,541	85,295	17,794	72.7%	66.9%	73.4%	54.0%
2006	80,717	15,568	87,326	16,147	3.2%	(11.2%)	2.4%	(9.3%)
2007	83,114	15,386	89,390	16,008	3.0%	(1.2%)	2.4%	(0.9%)
2008	80,611	14,389	87,788	14,893	(3.0%)	(6.5%)	(1.8%)	(7.0%)
2009	76,954	13,879	82,118	14,360	(4.5%)	(3.5%)	(6.5%)	(3.6%)
2010	81,068	16,209	86,994	16,687	5.3%	16.8%	5.9%	16.2%
2011	83,762	17,604	89,628	17,799	3.3%	8.6%	3.0%	6.7%
2012	88,687	17,431	93,763	17,329	5.9%	(1.0%)	4.6%	(2.6%)
2013	89,123	16,384	93,647	16,254	0.5%	(6.0%)	(0.1%)	(6.2%)
2014	90,567	16,662	96,015	16,518	1.6%	1.7%	2.5%	1.6%
2015	91,857	17,211	96,102	17,300	1.4%	3.3%	0.1%	4.7%

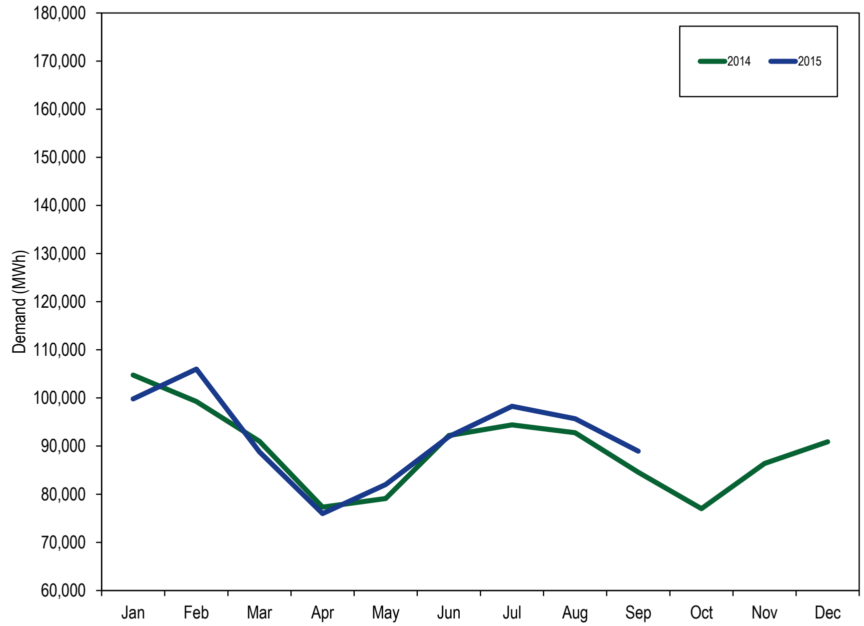
34 Accounting load is used here because PJM uses accounting load in the settlement process, which determines how much load customers pay for. In addition, the use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP, which excludes losses prior to June 1 and includes losses after June 1.

35 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, Monthly Average Load

Figure 3-15 compares the real-time, monthly average hourly loads in the first nine months of 2014 and 2015.

Figure 3-15 PJM real-time monthly average hourly load: January 2014 through September 2015



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 the first nine months of 2015 with those in the first nine months of 2014.[36]

36 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). PJM uses 60 degrees F for a heating degree day as stated in Manual 19.

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 hourly 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.

Heating degree days decreased 1.8 percent and cooling degree days increased 17.8 percent from the first nine months of 2014 to the first nine months of 2015.

Figure 3-16 PJM heating and cooling degree days: January 2014 through September 2015

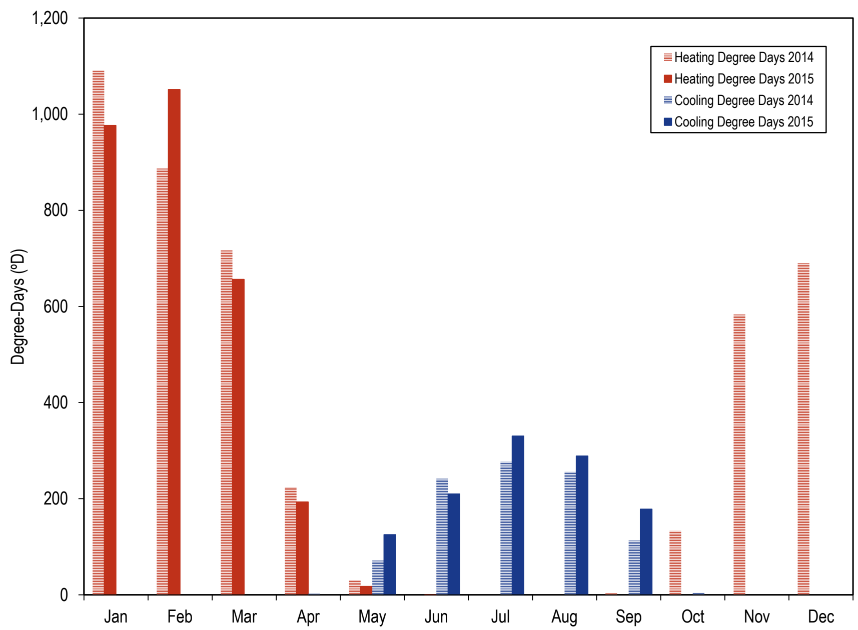


Table 3-16 PJM heating and cooling degree days: January 2014 through September 2015

	2014		2015		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	1,090	0	977	0	(10.4%)	0.0%
Feb	887	0	1,051	0	18.5%	0.0%
Mar	716	0	656	0	(8.4%)	0.0%
Apr	224	2	193	0	(13.8%)	0.0%
May	30	71	18	125	(40.3%)	75.8%
Jun	0	242	1	210	0.0%	(13.1%)
Jul	0	277	0	330	0.0%	19.2%
Aug	0	256	0	289	0.0%	12.9%
Sep	3	113	0	179	(100.0%)	57.7%
Oct	133	4				
Nov	583	0				
Dec	690	0				
Total	4,358	966	2,896	1,133	(1.8%)	17.8%

Day-Ahead Demand

PJM average day-ahead demand in the first nine months of 2015, including DECs and up to congestion transactions, decreased by 27.5 percent from the first nine months of 2014, from 156,542 MW to 113,553 MW.

PJM average day-ahead demand in the first nine months of 2015, including DECs, up to congestion transactions, and exports, decreased by 27.0 percent from the first nine month of 2014, from 160,425 MW to 117,090 MW.

The reduction in PJM day-ahead demand was a result of a substantial decrease in in UTCs beginning in September 2014 based on a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[37]

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

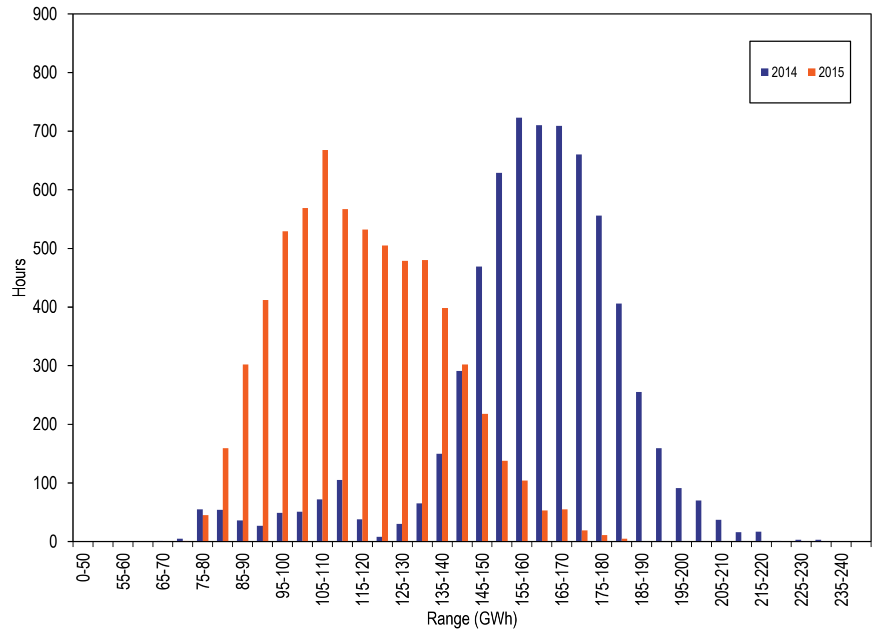
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of 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 (UTC).** A conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid.
- **Export.** An 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 the first nine months of 2014 and 2015.

Figure 3-17 Distribution of PJM day-ahead demand plus exports: January through September of 2014 and 2015[38]



38 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 the first nine months of each year of the 16-year period 2000 to 2015.[39]

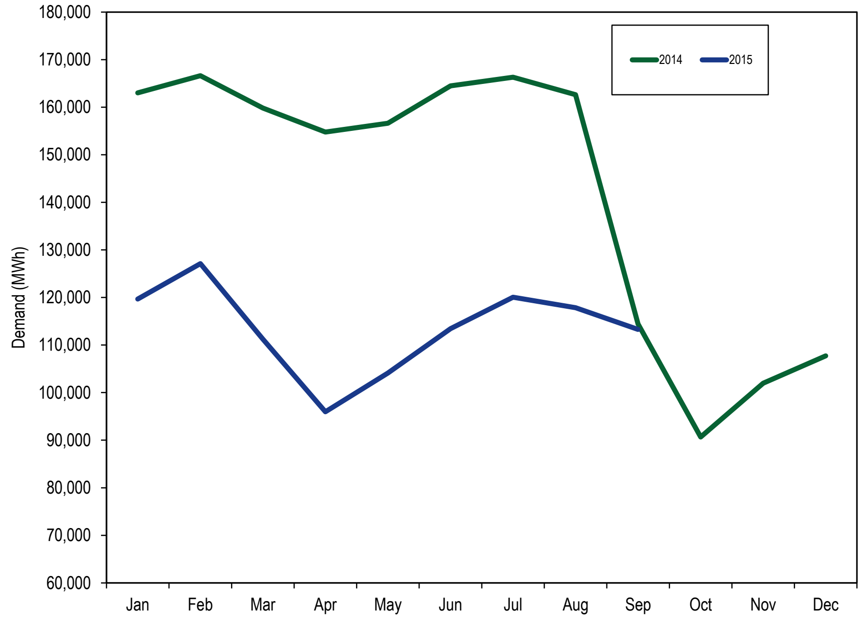
Table 3-17 PJM day-ahead average demand and day-ahead average hourly demand plus average hourly exports: January through September 2000 through 2015

	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	34,064	7,649	34,268	7,553	NA	NA	NA	NA
2001	33,944	7,016	34,444	6,817	(0.4%)	(8.3%)	0.5%	(9.7%)
2002	41,634	11,073	41,726	11,120	22.7%	57.8%	21.1%	63.1%
2003	45,371	8,377	45,477	8,354	9.0%	(24.4%)	9.0%	(24.9%)
2004	55,830	13,319	56,558	13,753	23.1%	59.0%	24.4%	64.6%
2005	93,525	19,126	96,302	19,455	67.5%	43.6%	70.3%	41.5%
2006	99,403	18,165	102,520	18,687	6.3%	(5.0%)	6.5%	(3.9%)
2007	107,295	17,580	110,711	17,949	7.9%	(3.2%)	8.0%	(4.0%)
2008	103,586	16,618	107,169	16,810	(3.5%)	(5.5%)	(3.2%)	(6.3%)
2009	96,020	16,995	99,084	17,117	(7.3%)	2.3%	(7.5%)	1.8%
2010	105,018	22,972	109,113	23,286	9.4%	35.2%	10.1%	36.0%
2011	113,724	22,444	117,533	22,651	8.3%	(2.3%)	7.7%	(2.7%)
2012	132,494	18,115	135,840	18,235	16.5%	(19.3%)	15.6%	(19.5%)
2013	145,139	18,667	148,444	18,696	9.5%	3.1%	9.3%	2.5%
2014	156,542	23,584	160,425	23,533	7.9%	26.3%	8.1%	25.9%
2015	113,553	19,788	117,090	19,951	(27.5%)	(16.1%)	(27.0%)	(15.2%)

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 the first nine months of 2014 and 2015. The reduction in PJM day-ahead demand was a result of a sharp decrease in in UTCs beginning in September 2014 based on a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[40]

Figure 3-18 PJM day-ahead monthly average hourly demand: January 2014 through September 2015



Real-Time and Day-Ahead Demand

Table 3-18 presents summary statistics for the first nine months of 2014 and 2015 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.

39 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.

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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Table 3-18 Cleared day-ahead and real-time demand (MWh): January through September 2014 and 2015

		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	2014	86,518	1,240	6,432	62,351	3,883	160,425	90,567	96,015	64,410	26,157
	2015	88,165	3,206	4,102	18,080	3,537	117,090	91,857	96,102	20,988	70,869
Median	2014	85,321	1,229	6,148	65,651	3,779	162,809	88,957	94,758	68,051	20,907
	2015	86,839	3,274	3,919	17,552	3,438	115,271	90,183	94,220	21,051	69,132
Standard Deviation	2014	15,755	171	1,471	17,350	974	23,533	16,662	16,518	7,015	9,647
	2015	16,310	601	1,337	4,519	948	19,951	17,211	17,300	2,651	14,560
Peak Average	2014	96,415	1,317	7,228	62,347	3,869	171,177	100,493	105,782	65,395	35,098
	2015	97,692	3,485	4,515	19,465	3,525	128,681	101,270	105,379	23,302	77,968
Peak Median	2014	95,721	1,318	7,026	66,186	3,806	173,802	99,462	104,973	68,830	30,632
	2015	97,283	3,562	4,353	18,687	3,388	127,574	100,643	104,951	22,623	78,020
Peak Standard Deviation	2014	12,725	159	1,441	16,853	965	21,487	13,807	13,611	7,876	5,931
	2015	13,311	563	1,246	4,646	995	16,983	14,524	14,817	2,166	12,358
Off-Peak Average	2014	77,865	1,173	5,735	62,355	3,895	151,023	81,887	87,475	63,548	18,339
	2015	79,502	2,952	3,727	16,821	3,548	106,550	83,297	87,667	18,883	64,413
Off-Peak Median	2014	76,074	1,168	5,515	65,234	3,771	154,557	79,619	85,595	68,962	10,657
	2015	77,039	2,980	3,499	16,375	3,482	103,270	80,568	84,815	18,456	62,113
Off-Peak Standard Deviation	2014	12,775	152	1,096	17,776	981	21,095	13,865	13,897	7,198	6,667
	2015	13,758	515	1,305	4,005	902	16,263	14,830	14,913	1,350	13,480

Figure 3-19 shows the average hourly cleared volumes of day-ahead demand and real-time demand for January through September of 2015. 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.

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Figure 3-19 Day-ahead and real-time demand (Average hourly volumes): January through September 2015

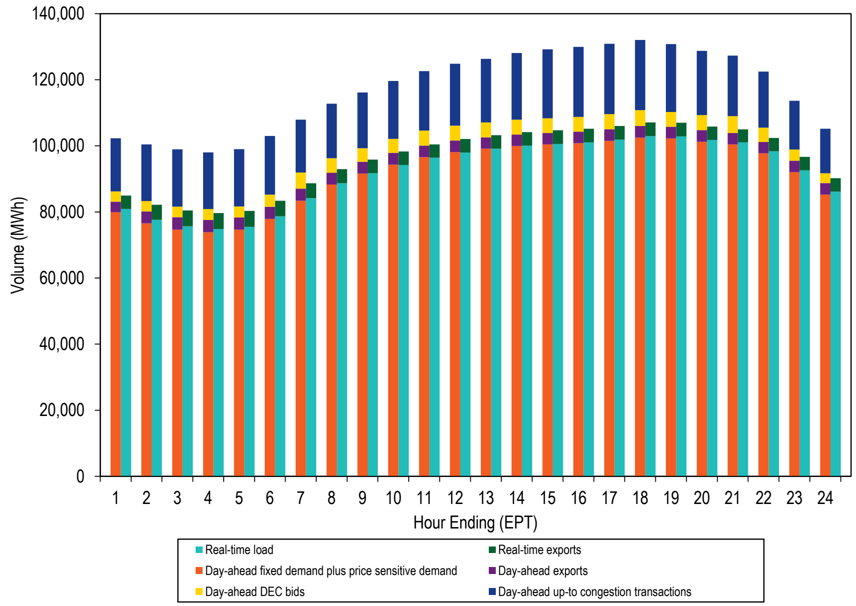
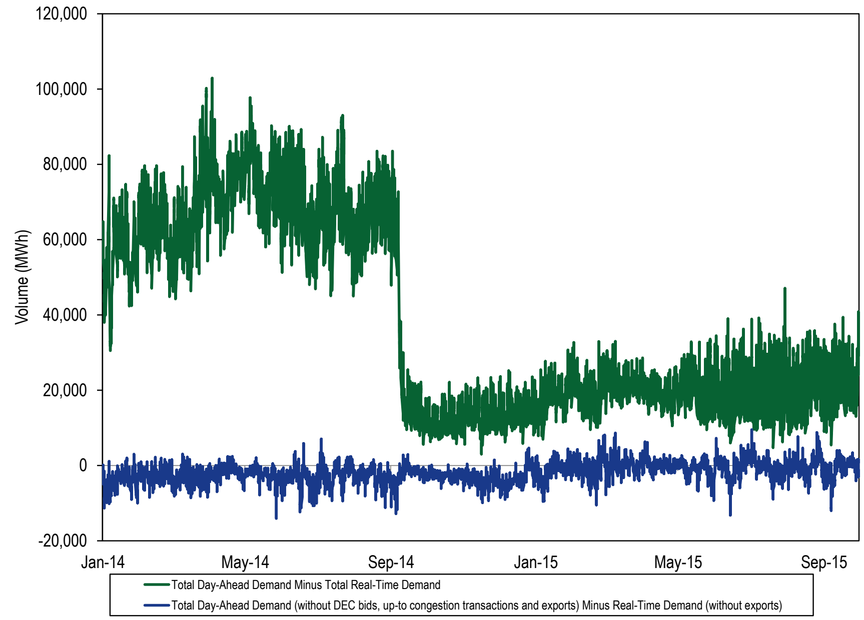


Figure 3-20 shows the difference between the day-ahead and real-time average daily demand in the first nine months of 2014 and 2015. The substantial decrease in UTC MW in September, which resulted in a corresponding decrease in day-ahead demand, was a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[41]

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

Figure 3-20 Difference between day-ahead and real-time demand (Average daily volumes): January 2014 through September 2015



Supply and Demand: Load and Spot Market

Real-Time Load and Spot Market

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

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

The PJM system's reliance on self-supply, bilateral contracts and spot purchases to meet real-time load is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Real-Time Energy Market for each hour. Table 3-19 shows the monthly average share of real-time load served by self-supply, bilateral contracts and spot purchase January 2014 through September 2015 based on parent company. In the first nine months of 2015, 11.7 percent of real-time load was supplied by bilateral contracts, 29.2 percent by spot market purchase and 59.1 percent by self-supply. Compared with the first nine months of 2014, reliance on bilateral contracts increased by 1.1 percentage points, reliance on spot supply increased by 2.5 percentage points and reliance on self-supply decreased by 3.6 percentage points.

Table 3-19 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: January 2014 through September 2015

	2014			2015			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	9.5%	27.9%	62.6%	13.4%	23.2%	63.5%	3.9%	(4.7%)	0.9%
Feb	9.2%	27.3%	63.5%	12.8%	23.1%	64.1%	3.7%	(4.2%)	0.6%
Mar	9.7%	27.2%	63.0%	12.3%	25.9%	61.8%	2.5%	(1.3%)	(1.2%)
Apr	9.1%	29.7%	61.2%	11.4%	37.8%	50.8%	2.3%	8.1%	(10.4%)
May	9.7%	28.8%	61.5%	10.1%	37.3%	52.6%	0.4%	8.5%	(8.9%)
Jun	10.6%	29.0%	60.4%	9.9%	37.4%	52.6%	(0.7%)	8.5%	(7.8%)
Jul	11.2%	25.7%	63.1%	11.8%	25.9%	62.3%	0.7%	0.1%	(0.8%)
Aug	11.2%	25.4%	63.4%	12.1%	25.8%	62.2%	0.8%	0.4%	(1.2%)
Sep	11.2%	25.6%	63.2%	11.9%	26.4%	61.7%	0.7%	0.8%	(1.5%)
Oct	11.5%	25.1%	63.4%						
Nov	11.8%	24.9%	63.4%						
Dec	12.9%	23.4%	63.7%						
Annual	10.6%	26.7%	62.7%	11.7%	29.2%	59.1%	1.1%	2.5%	(3.6%)

Day-Ahead Load and Spot Market

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

The PJM system's reliance on self-supply, bilateral contracts, and spot purchases to meet day-ahead demand (cleared fixed-demand, price-sensitive load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve demand in the Day-Ahead Energy Market for each hour. Table 3-20 shows the monthly average share of day-ahead demand served by self-supply, bilateral contracts and spot purchases in January 2014 through September 2015, based on parent companies. In the first nine months of 2015, 10.0 percent of day-ahead demand was supplied by bilateral contracts, 25.7 percent by spot market purchases, and 64.3 percent by self-supply. Compared with the first nine months of 2014, reliance on

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bilateral contracts increased by 0.5 percentage points, reliance on spot supply decreased by 0.5 percentage points, and reliance on self-supply decreased by 0.0 percentage points.

Table 3-20 Monthly average percentage of day-ahead self-supply demand, bilateral supply demand, and spot-supply demand based on parent companies: January 2014 through September 2015

	2014			2015			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	11.0%	28.9%	60.1%	11.1%	23.1%	65.8%	0.1%	(5.8%)	5.7%
Feb	8.4%	26.5%	65.1%	10.5%	23.2%	66.2%	2.1%	(3.3%)	1.2%
Mar	8.6%	27.8%	63.6%	10.2%	26.2%	63.7%	1.5%	(1.6%)	0.1%
Apr	7.9%	29.8%	62.3%	10.5%	27.9%	61.6%	2.6%	(1.9%)	(0.7%)
May	8.1%	29.1%	62.9%	9.7%	26.2%	64.0%	1.6%	(2.8%)	1.2%
Jun	9.4%	26.2%	64.4%	9.9%	28.7%	61.4%	0.5%	2.5%	(3.0%)
Jul	9.6%	25.2%	65.2%	9.7%	25.7%	64.6%	0.0%	0.5%	(0.5%)
Aug	9.7%	24.6%	65.7%	9.5%	25.3%	65.2%	(0.3%)	0.7%	(0.5%)
Sep	9.4%	25.0%	65.6%	9.0%	26.4%	64.6%	(0.4%)	1.3%	(1.0%)
Oct	9.6%	24.5%	65.9%						
Nov	10.7%	24.2%	65.0%						
Dec	11.3%	23.2%	65.5%						
Annual	9.5%	26.2%	64.2%	10.0%	25.7%	64.3%	0.5%	(0.5%)	0.0%

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.

The analysis of the application of the three pivotal supplier test demonstrates that it is working for most hours to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive. However, there are some issues with the application of the TPS test in the Day-Ahead Energy Market. There is no tariff or manual language that defines in detail the application of the TPS test in the Day-Ahead Energy Market.

In both the Day-Ahead and Real-Time Energy Markets, generators have the ability to avoid mitigation by using varying markups in their price based offers, offering different operating parameters in their price based and cost based offers, and using different fuels in their price based and cost based offers. These issues can be solved by simple rule changes.

When an owner fails the TPS test, the units offered by the owner that are committed to provide relief are committed on the cheaper of cost or price based offers. With the ability to submit offer curves with varying markups at different output levels in the price based offer, units can avoid mitigation by using a low markup at low output levels and a high markup at higher output levels. Figure 3-21 shows an example of offers from a unit that has a negative markup at the economic minimum MW level and a positive markup at the economic maximum MW level. The result would be that a unit that failed the TPS test would be committed on its price based offer even though the price based offer is higher cost at higher output levels and includes positive markups, inconsistent with the explicit goal of the TPS test rules.

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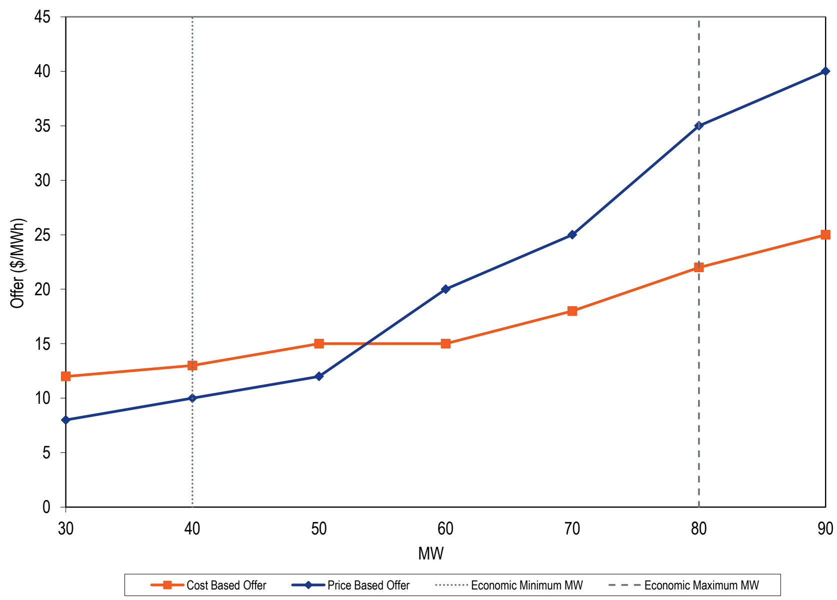
Figure 3-21 Offers with varying markups at different MW output levels

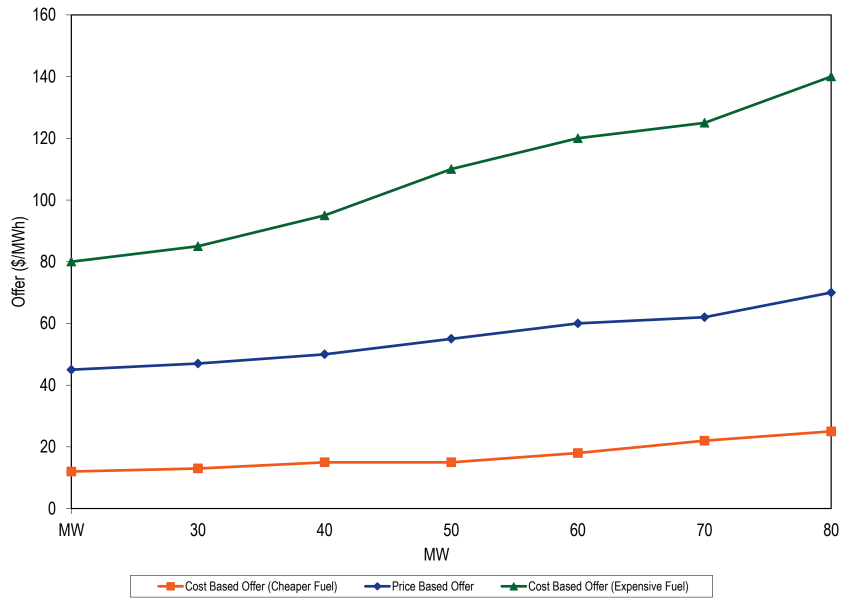


Offering a different economic minimum MW level, different minimum run times, different start up and notification times on the cost based and price based offers can also be used to avoid mitigation. For example, a unit may offer a lower economic minimum MW level on the price based offer than the cost based offer. Such a unit may appear to be cheaper to commit on the price based offer even with a positive markup because the total cost of commitment (calculated as a product of MW and the offer in dollars per MWh plus the startup and no-load cost) can be lower on price based offer at the lower economic minimum level compared to cost based offer at a higher economic minimum level. A unit may offer its price based offer with a negative markup over its cost based offer, but have a longer minimum run time (MRT) on the price based offer.

In case of dual fuel units, if the price based offer uses a cheaper fuel and the cost based offer uses a more expensive fuel, the price based offer will appear to be lower cost even when it includes a markup. Figure 3-22 shows an example of offers by a dual fuel unit, where the active cost based offer uses a more expensive fuel and the price based offer uses a cheaper fuel and includes a markup.

These issues can be solved by simple rule changes.[42]

Figure 3-22 Dual fuel unit offers



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.

42 The MMU proposed these offer rule changes as part of a broader reform to address generator offer flexibility and associated impact on market power mitigation rules in the Generator Offer Flexibility Senior Task Force (GOFSTF).

Table 3-21 Offer-capping statistics – energy only: January through September, 2011 to 2015

	Real Time		Day Ahead	
(Jan-Sep)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2011	0.7%	0.3%	0.0%	0.0%
2012	1.1%	0.6%	0.1%	0.1%
2013	0.4%	0.1%	0.2%	0.0%
2014	0.5%	0.2%	0.2%	0.1%
2015	0.4%	0.2%	0.2%	0.1%

Table 3-22 shows the offer capping percentages including units committed to provide constraint relief and units committed to provide black start service and reactive support. The units that are committed and offer capped for reliability reasons increased in the first nine months from 2011 through 2013. Before 2011, the units that ran to provide black start service and reactive support were generally economic in the energy market. From 2011 through 2013, the percentage of hours when these units were not economic (and were therefore committed on their cost schedule for reliability reasons) increased. This trend reversed in the first nine months of 2014 and 2015 because higher LMPs (in the first three months) resulted in the increased economic dispatch of black start and reactive service resources. As of April 2015, the units that were committed for black start previously no longer provide black start service, and are not included in the offer capping statistics for reliability. PJM also created closed loop interfaces to, in some cases, model reactive constraints with a corresponding impact on LMP, which contributed to the reduction in units offer capped for reliability. These units are now committed for the modeled closed loop interface constraints and offer capped for providing constraint relief. They are included in the offer capping percentages in Table 3-21.

Table 3-22 Offer-capping statistics for energy and reliability: January through September, 2011 through 2015

	Real Time		Day Ahead	
(Jan-Sep)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2011	1.5%	0.6%	0.0%	0.0%
2012	1.4%	0.8%	0.2%	0.2%
2013	2.9%	2.3%	3.2%	2.1%
2014	0.8%	0.6%	0.5%	0.4%
2015	0.8%	0.9%	0.7%	0.8%

Table 3-23 shows the offer capping percentages for units committed to provide black start service and reactive support. The data in Table 3-23 is the difference between the offer cap percentages shown in Table 3-22 and Table 3-21.

Table 3-23 Offer-capping statistics for reliability: January through September, 2011 through 2015

	Real Time		Day Ahead	
(Jan-Sep)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2011	0.8%	0.3%	0.0%	0.0%
2012	0.3%	0.2%	0.1%	0.1%
2013	2.5%	2.1%	3.0%	2.1%
2014	0.3%	0.3%	0.3%	0.3%
2015	0.5%	0.7%	0.5%	0.7%

Table 3-24 presents data on the frequency with which units were offer capped in the first nine months of 2014 and 2015, for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market. Table 3-24 shows that four units were offer capped for 90 percent or more of their run hours in the first nine months of 2015 compared to none in the first nine months of 2014.

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Table 3-24 Real-time offer-capped unit statistics: January through September, 2014 through 2015

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	(Jan - Sep)	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2015	1	0	0	0	0	3
	2014	0	0	0	0	0	0
80% and < 90%	2015	0	0	0	0	1	8
	2014	0	1	1	0	2	0
75% and < 80%	2015	0	0	0	2	0	1
	2014	1	1	0	0	1	0
70% and < 75%	2015	0	0	0	0	1	5
	2014	0	0	0	0	1	0
60% and < 70%	2015	0	0	0	0	1	10
	2014	0	0	0	0	6	4
50% and < 60%	2015	0	0	0	0	0	7
	2014	0	0	0	0	3	8
25% and < 50%	2015	0	0	0	0	2	25
	2014	0	0	9	1	10	43
10% and < 25%	2015	1	0	3	3	3	29
	2014	0	0	0	1	8	42

TPS Test Statistics

In the first nine months of 2015, the AEP, AP, ATSI, BGE, ComEd, DEOK, DLCO, Dominion, DPL, JCPL, MetEd, PECO, PENELEC, and PSEG control zones experienced congestion resulting from one or more constraints binding for 75 or more hours or resulting from an interface constraint. The AECO, DAY, EKPC, Pepco, PPL, and RECO control zones did not have constraints binding for 75 or more hours in the first nine months of 2015. Table 3-25 shows that AEP, BGE, ComEd, Dominion, PPL and PSEG were the control zones experienced congestion resulting from one or more constraints binding for 75 or more hours or resulting from an interface constraint that was binding for one or more hours in every year in January through September of 2009 through 2015.

Table 3-25 Numbers of hours when control zones experienced congestion resulting from one or more constraints binding for 75 or more hours or from an interface constraint: January through September, 2009 through 2015

	Year (Jan - Sep)						
	2009	2010	2011	2012	2013	2014	2015
AECO	149	163	234	NA	NA	NA	192
AEP	1,005	975	2,197	178	2,018	1,821	1,891
AP	1,297	3,344	1,805	89	NA	170	451
ATSI	140	NA	NA	208	68	481	424
BGE	127	274	368	1,582	1,192	4,416	6,006
ComEd	784	2,108	872	1,808	3,169	1,928	1,708
DEOK	NA	NA	NA	185	NA	NA	NA
DLCO	156	393	NA	209	NA	223	617
Dominion	456	889	1,593	559	894	77	1,341
DPL	NA	111	NA	382	783	542	1,138
JCPL	NA	NA	NA	NA	NA	NA	79
Met-Ed	NA	168	NA	NA	NA	NA	222
PECO	247	NA	276	NA	390	1,826	718
PENELEC	80	96	77	NA	NA	2,147	1,287
Pepco	149	NA	76	143	200	41	NA
PPL	176	117	40	146	609	148	224
PSEG	379	515	1,132	259	1,993	2,268	2,509

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 the first nine months of 2015.[43] 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.

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

Table 3-26 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the transfer interface constraints.

Table 3-26 Three pivotal supplier test details for interface constraints: January through September, 2015

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	385	477	15	2	13
	Off Peak	424	574	15	2	13
AEP - DOM	Peak	436	297	8	0	8
	Off Peak	254	278	7	0	7
AP South	Peak	341	423	11	2	10
	Off Peak	276	438	11	1	10
Bedington - Black Oak	Peak	175	233	14	2	12
	Off Peak	175	220	13	2	10
Central	Peak	945	918	14	2	12
	Off Peak	667	754	13	3	10
Eastern	Peak	837	740	13	0	13
	Off Peak	897	763	12	4	9
Western	Peak	617	633	13	1	12
	Off Peak	476	508	12	1	11

Table 3-27 Summary of three pivotal supplier tests applied for interface constraints: January through September, 2015

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	1,817	58	3%	38	2%	66%
	Off Peak	1,801	107	6%	59	3%	55%
AEP - DOM	Peak	148	21	14%	18	12%	86%
	Off Peak	106	11	10%	4	4%	36%
AP South	Peak	118	6	5%	3	3%	50%
	Off Peak	65	10	15%	2	3%	20%
Bedington - Black Oak	Peak	1,572	58	4%	29	2%	50%
	Off Peak	960	32	3%	12	1%	38%
Central	Peak	198	3	2%	3	2%	100%
	Off Peak	102	1	1%	0	0%	0%
Eastern	Peak	86	3	3%	3	3%	100%
	Off Peak	14	0	0%	0	0%	0%
Western	Peak	429	9	2%	5	1%	56%
	Off Peak	116	0	0%	0	0%	0%

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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 3-27 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.

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.[44] 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 3-28 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using unadjusted cost offers. Table 3-29 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using adjusted cost offers. The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point. In the first nine months of 2015, 85.7 percent of marginal units had average dollar markups less than zero. The data show that some marginal units did have substantial markups. Using the unadjusted cost offers, the highest markup in the first nine months of 2015 was $792.21 while the highest markup in the first nine months of 2014 was $922.26.

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

Table 3-28 Average, real-time marginal unit markup index (By offer price category unadjusted): January through September, 2014 through 2015

	2014 (Jan - Sep)			2015 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.10)	($2.17)	16.4%	(0.05)	($2.72)	41.4%
$25 to $50	(0.01)	($1.14)	57.3%	(0.03)	($1.43)	44.3%
$50 to $75	0.05	$2.14	8.6%	0.08	$4.07	3.5%
$75 to $100	0.11	$8.16	2.5%	0.13	$10.06	1.3%
$100 to $125	0.04	$3.68	4.9%	0.11	$10.97	1.2%
$125 to $150	0.11	$13.80	1.2%	0.06	$6.67	1.6%
>= $150	0.09	$22.17	8.9%	0.05	$12.83	6.7%

Table 3-29 Average, real-time marginal unit markup index (By offer price category adjusted): January through September, 2014 through 2015

	2014 (Jan - Sep)			2015 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.07)	($1.32)	16.4%	(0.02)	($1.64)	41.4%
$25 to $50	0.03	$0.37	57.3%	0.02	$0.19	44.3%
$50 to $75	0.06	$2.69	8.6%	0.10	$5.15	3.5%
$75 to $100	0.11	$8.71	2.5%	0.13	$10.55	1.3%
$100 to $125	0.04	$3.81	4.9%	0.11	$11.29	1.2%
$125 to $150	0.11	$13.98	1.2%	0.06	$6.86	1.6%
>= $150	0.09	$22.35	8.9%	0.05	$13.04	6.7%

Day-Ahead Markup

Table 3-30 shows the average markup index of marginal units in the Day-Ahead Energy Market, by offer price category using unadjusted offers. In the first nine months of 2015, 40.3 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.00. The data show that some marginal units in the first nine months of 2014 did have substantial markups. The average markup index decreased significantly, for example, from 0.14 in the first nine months of 2014, to -0.01 in the first nine months of 2015 in the offer price category from $100 to $125.

Table 3-30 Average day-ahead marginal unit markup index (By offer price category, unadjusted): January through September, 2014 and 2015

	2014 (Jan - Sep)			2015 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.08)	($2.07)	14.3%	0.04	($0.68)	38.1%
$25 to $50	(0.02)	($1.07)	69.2%	0.04	$1.10	51.4%
$50 to $75	0.04	$1.98	10.2%	0.15	$8.71	3.0%
$75 to $100	0.07	$5.46	1.5%	0.05	$3.69	1.3%
$100 to $125	0.14	$15.91	1.1%	0.00	($2.01)	0.9%
$125 to $150	0.02	($2.02)	1.1%	(0.00)	($2.30)	1.2%
>= $150	0.07	$13.94	2.5%	0.03	$4.39	3.3%

Table 3-31 shows the average markup index of marginal units in the Day-Ahead Energy Market, by offer price category using adjusted offers. In the first nine months of 2015, 2.2 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.00. The average markup index decreased significantly, for example, from 0.15 in the first nine months of 2014, to 0.00 in the first nine months of 2015 in the offer price category from $100 to $125.

Table 3-31 Average day-ahead marginal unit markup index (By offer price category, adjusted): January through September, 2014 through 2015

	2014 (Jan - Sep)			2015 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.02)	($0.51)	14.3%	0.06	$0.18	38.1%
$25 to $50	0.04	$0.96	69.2%	0.08	$2.38	51.4%
$50 to $75	0.07	$3.58	10.2%	0.17	$9.74	3.0%
$75 to $100	0.08	$5.95	1.5%	0.05	$3.85	1.3%
$100 to $125	0.15	$16.14	1.1%	0.00	($1.83)	0.9%
$125 to $150	0.02	($1.86)	1.1%	0.00	($2.05)	1.2%
>= $150	0.07	$14.70	2.5%	0.03	$4.44	3.3%

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.[45] 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 PJM 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 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 on the elimination of FMU adders 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. PJM submitted the joint MMU/PJM proposal to the Commission pursuant to section 206 of the Federal Power Act. On October 31, 2014, the Commission conditionally approved the filing and the new rule became effective November 1, 2014.

45 110 FERC ¶ 61,053 (2005).

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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 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.[46]

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.[47] 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.[48] 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 zero in December 2014 (See Table 3-33).

Table 3-32 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 2014 and January through September, 2015.[49] In the first nine months of 2015, no units qualified as an FMU or AU.

Table 3-32 Frequently mitigated units and associated units by total months eligible: 2014 and January through September, 2015

Months Adder-Eligible	2014	2015
1	23	0
2	6	0
3	0	0
4	4	0
5	4	0
6	15	0
7	2	0
8	5	0
9	8	0
10	5	
11	39	
12	0	
Total	111	0

46 PJM. OA, Schedule 1 § 6.4.2.

47 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.

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

49 The data on FMUs and AUs reported in the *2015 Quarterly State of the Market Report for PJM: January through March*, reflected an incorrect calculation by the MMU. In fact, there should have been zero FMUs and AUs since the implementation of the new FMU rules effective for December 2014.

Figure 3-23 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 September 30, 2015, 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 106 of the 117 possible months, and 74 of the 351 units (21.1 percent) qualified for an adder in more than half of the possible months.

Figure 3-23 Frequently mitigated units and associated units total months eligible: February, 2006 through September, 2015

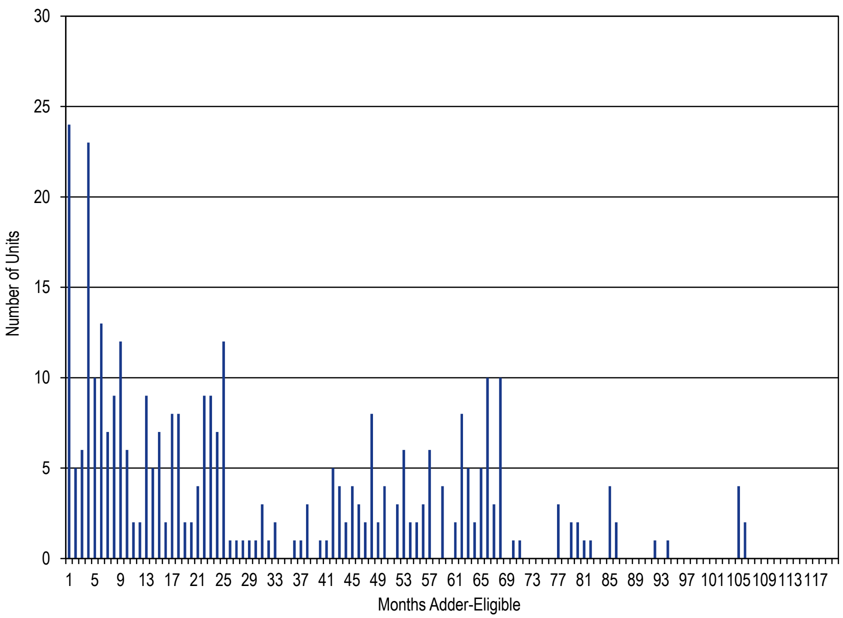

Table 3-33 shows, by month, the number of FMUs and AUs in 2014 and January through September, 2015. For example, in November 2014, there were 25 FMUs and AUs in Tier 1, 15 FMUs and AUs in Tier 2, and 15 FMUs and AUs in Tier 3. In the first nine months of 2015, no units qualified as an FMU or AU.

Table 3-33 Number of frequently mitigated units and associated units (By month): 2014 and January through September, 2015

	2014				2015			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	7	27	49	83	0	0	0	0
February	13	17	48	78	0	0	0	0
March	30	18	33	81	0	0	0	0
April	30	20	29	79	0	0	0	0
May	36	19	23	78	0	0	0	0
June	38	18	21	77	0	0	0	0
July	27	13	23	63	0	0	0	0
August	37	15	19	71	0	0	0	0
September	22	13	20	55	0	0	0	0
October	16	11	19	46				
November	25	15	15	55				
December	0	0	0	0				

Figure 3-24 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 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 starting in December 2014 was the result of the revised rules for FMUs.

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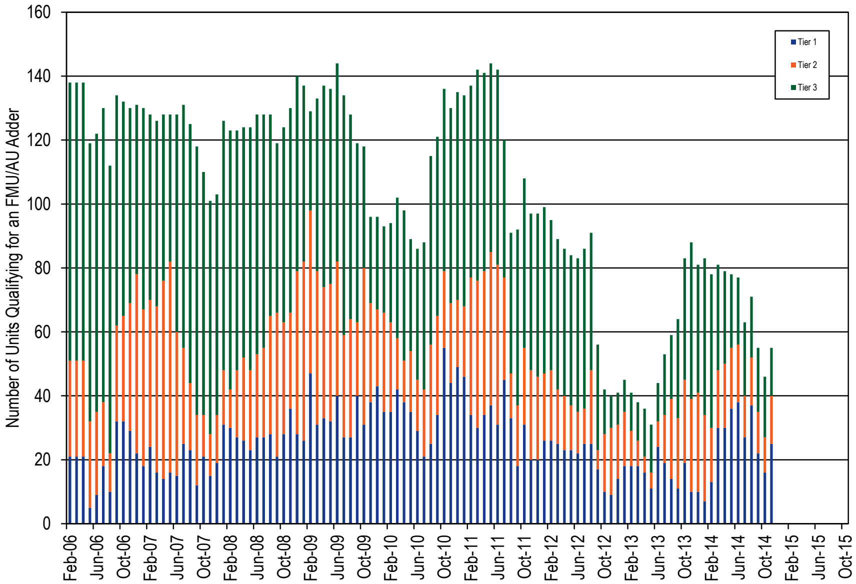
Figure 3-24 Frequently mitigated units and associated units (By month): February 2006 through September 2015



An error in the Market Monitoring Unit's (MMU) monthly calculation used to determine unit eligibility for the Frequently Mitigated Unit (FMU) adder under the new FMU rules resulted in a number of generators permitted to use an adder when no units should have been permitted to use an adder. This occurred for the period from December 1, 2014, the first day that the new FMU rules had an effect, to April 22, 2015. The affected generators were immediately directed to cease using FMU adders when the issue was discovered. The MMU has evaluated the impact of the incorrect FMU status on the markets and found that there was no impact on the day-ahead market outcomes. In the four months where the units were incorrectly allowed to use FMU adders, a total of four five-minute intervals in the real-time market were affected. The impact on hourly PJM system-wide load-weighted real-time LMP ranged between $0.19 and $0.58 per MWh for the three hours affected. There was no impact on the monthly PJM system-wide load-weighted real-time LMP.

Virtual Offers and Bids

There is a substantial volume of virtual offers and bids in the PJM Day-Ahead Energy 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.[50] 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 3-25 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 2015.

50 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>.

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Figure 3-25 PJM day-ahead aggregate supply curves: 2015 example day

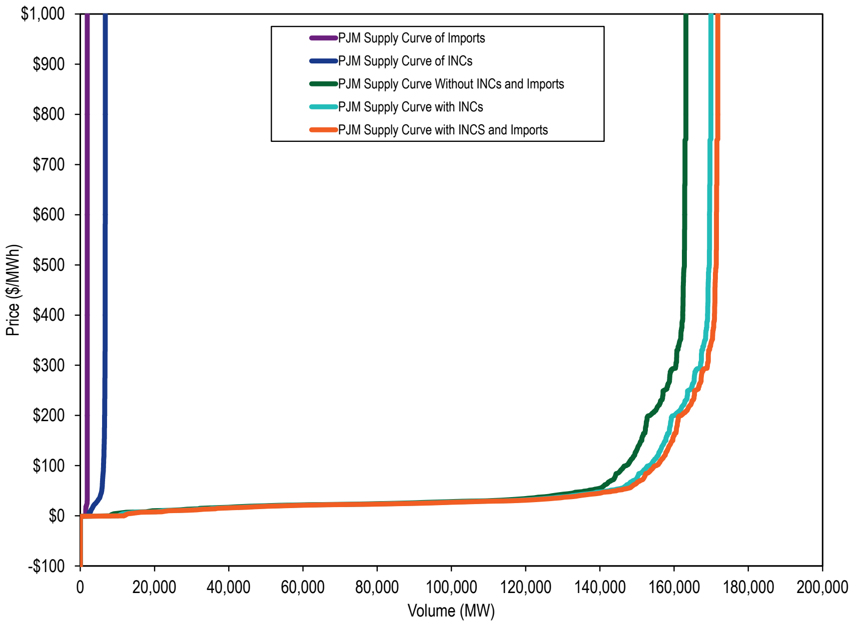

Table 3-34 shows the average hourly number of increment offers and decrement bids and the average hourly MW January 2014 through September 2015. In the first nine months of 2015, the average hourly submitted and cleared increment offer MW increased 42.2 and 35.3 percent, and the average hourly submitted and cleared decrement bid MW decreased 21.0 and 35.4 percent, compared to the first nine months of 2014.

Table 3-34 Hourly average number of cleared and submitted INCs, DECs by month: January 2014 through September 2015

	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
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
2015 Jan	4,350	6,447	78	398	5,153	7,320	76	295
2015 Feb	4,754	7,109	116	578	4,511	7,445	72	409
2015 Mar	4,973	8,689	142	760	4,305	8,894	101	648
2015 Apr	4,511	6,351	187	558	3,453	6,990	84	451
2015 May	5,089	7,459	181	656	4,171	6,823	94	404
2015 June	4,592	7,043	143	697	4,196	6,696	89	410
2015 July	4,101	6,534	128	745	3,335	5,830	86	448
2015 August	4,457	6,956	135	749	3,433	5,506	74	398
2015 September	4,527	6,772	148	733	4,391	7,030	112	437
2015 Annual	4,594	7,043	140	653	4,102	6,943	88	433

The reduction in up to congestion transactions (UTC) continued, following a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[51] Table 3-35 shows the average hourly number of up to congestion transactions and the average hourly MW for January 2014 through September 2015. In the first nine months of 2015, the average hourly up to congestion submitted MW decreased 62.4 percent and cleared MW decreased 71.0 percent, compared to the first nine months of 2014, as a result of the decreases after September 8.

51 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 3-35 Hourly average of cleared and submitted up to congestion bids by month: January 2014 through September 2015

	Up-to Congestion			
Year	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
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
2015 Jan	15,903	46,626	806	2,132
2015 Feb	17,255	57,318	892	2,695
2015 Mar	18,382	72,906	978	2,909
2015 Apr	16,300	73,446	811	2,734
2015 May	18,929	81,358	941	3,219
2015 Jun	17,714	81,452	896	3,220
2015 Jul	18,883	88,543	952	3,502
2015 Aug	18,490	102,084	1,126	4,291
2015 Sep	20,779	108,730	1,451	4,909
2015 Annual	18,077	79,307	984	3,293

Table 3-36 shows the average hourly number of import and export transactions and the average hourly MW for January 2014 through September 2015. In the first nine months of 2015, the average hourly submitted and cleared import transaction MW increased 7.6 and 4.3 percent, and the average hourly submitted and cleared export transaction MW decreased 12.4 and 11.0 percent, compared to the first nine months of 2014.

Table 3-36 Hourly average number of cleared and submitted import and export transactions by month: January 2014 through September 2015

	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
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
2015 Jan	2,579	2,716	15	17	4,473	4,559	26	26
2015 Feb	2,588	2,726	17	19	4,383	4,469	23	25
2015 Mar	2,484	2,668	16	18	3,268	3,302	16	17
2015 Apr	2,531	2,638	18	21	2,624	2,626	13	13
2015 May	2,339	2,482	18	20	2,612	2,623	17	17
2015 Jun	2,269	2,349	14	16	2,895	2,906	14	14
2015 Jul	2,319	2,445	16	18	2,961	2,983	14	14
2015 Aug	2,410	2,549	14	16	3,209	3,239	15	15
2015 Sep	1,854	2,015	11	14	3,873	3,913	18	18
2015 Annual	2,374	2,509	15	18	3,358	3,393	17	18

Table 3-37 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 January 2014 through September of 2015.

Table 3-37 Type of day-ahead marginal units: January 2014 through September of 2015

	2014						2015					
	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	2.7%	0.1%	94.5%	1.4%	1.2%	0.0%	14.2%	0.5%	71.9%	6.9%	6.3%	0.1%
Feb	2.0%	0.3%	94.8%	1.9%	1.1%	0.0%	13.1%	0.4%	73.1%	7.6%	5.6%	0.1%
Mar	2.5%	0.2%	94.7%	1.5%	1.0%	0.0%	10.0%	0.7%	73.3%	10.6%	5.3%	0.0%
Apr	2.3%	0.0%	95.1%	1.4%	1.2%	0.0%	10.4%	0.3%	73.2%	10.8%	5.3%	0.0%
May	1.6%	0.0%	92.0%	4.0%	2.4%	0.0%	10.2%	0.1%	75.2%	9.2%	5.3%	0.0%
Jun	2.0%	0.0%	94.6%	2.0%	1.4%	0.0%	8.0%	0.1%	78.2%	9.5%	4.1%	0.0%
Jul	2.1%	0.0%	93.9%	2.1%	1.9%	0.0%	7.2%	0.1%	81.1%	7.8%	3.8%	0.0%
Aug	2.2%	0.0%	94.8%	1.5%	1.6%	0.0%	6.0%	0.1%	83.4%	7.1%	3.3%	0.0%
Sep	6.9%	0.1%	84.1%	5.5%	3.5%	0.0%	7.2%	0.2%	80.0%	7.5%	5.1%	0.0%
Oct	12.2%	0.1%	64.0%	14.5%	9.2%	0.0%						
Nov	10.1%	0.2%	64.9%	14.6%	10.1%	0.0%						
Dec	12.6%	0.2%	67.2%	12.4%	7.6%	0.0%						
Total	3.3%	0.1%	91.0%	3.3%	2.3%	0.0%	9.7%	0.3%	76.5%	8.6%	4.9%	0.0%

Figure 3-26 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month for the period from January 2005 through September 2015. Figure 3-27 shows the daily volume of bid and cleared INC, DEC and up to congestion bids for the period for January 2014 through September 2015 in order to show the drop off in UTC volumes compared to volumes in the last 18 months.

Figure 3-26 Monthly bid and cleared INCs, DECs, and UTCs (MW): January 2005 through September 2015

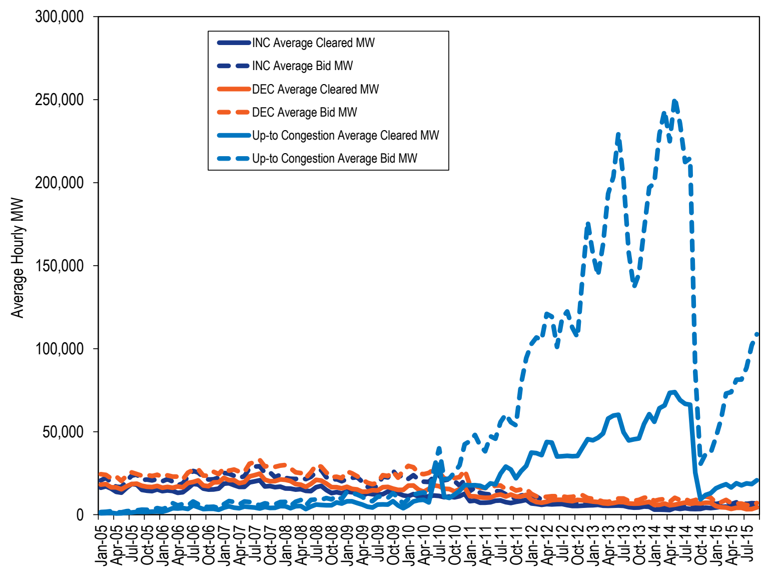

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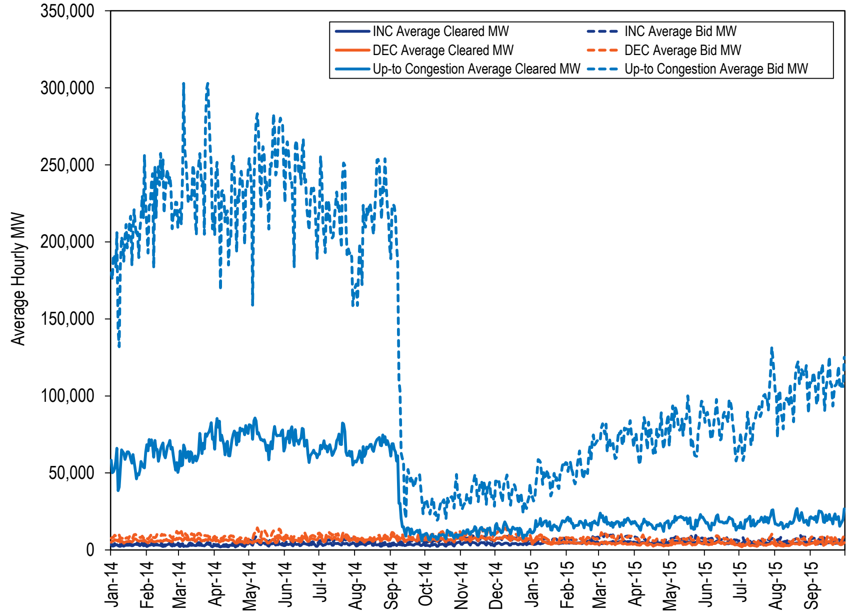
Figure 3-27 Daily bid and cleared INCs, DECs, and UTCs (MW): January 2014 through September 2015



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 3-38 shows, for the first nine months of 2014 and 2015, the total increment offers and decrement bids by whether the parent organization is financial or physical.

Table 3-38 PJM INC and DEC bids by type of parent organization (MW): January through September 2014 and 2015

	2014 (Jan-Sep)		2015 (Jan-Sep)	
Category	Total Virtual Bids MW	Percent	Total Virtual Bids MW	Percent
Financial	29,684,566	33.1%	39,125,795	42.7%
Physical	60,107,444	66.9%	52,493,699	57.3%
Total	89,792,010	100.0%	91,619,495	100.0%

Table 3-39 shows, for the first nine months of 2014 and 2015, the total up to congestion transactions by the type of parent organization.

Table 3-39 PJM up to congestion transactions by type of parent organization (MW): January through June 2014 and 2015

	2014 (Jan-Sep)		2015 (Jan-Sep)	
Category	Total Up-to Congestion MW	Percent	Total Up-to Congestion MW	Percent
Financial	397,253,998	97.3%	94,242,214	79.8%
Physical	11,208,929	2.7%	23,866,728	20.2%
Total	408,462,927	100.0%	118,108,942	100.0%

Table 3-40 shows for the first nine months of 2014 and 2015, the total import and export transactions by whether the parent organization is financial or physical.

Table 3-40 PJM import and export transactions by type of parent organization (MW): January through September 2014 and 2015

	2014 (Jan-Sep)		2015 (Jan-Sep)	
Category	Total Import and Export MW	Percent	Total Import and Export MW	Percent
Financial	15,806,252	39.1%	16,654,167	43.0%
Physical	24,661,550	60.9%	22,068,522	57.0%
Total	40,467,802	100.0%	38,722,688	100.0%

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Table 3-41 shows increment offers and decrement bids bid by top ten locations for the first nine months of 2014 and 2015.

Table 3-41 PJM virtual offers and bids by top ten locations (MW): January through September 2014 and 2015

2014 (Jan-Sep)					2015 (Jan-Sep)				
Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	9,894,171	10,863,829	20,758,000	WESTERN HUB	HUB	14,538,868	16,573,390	31,112,258
MISO	INTERFACE	343,925	5,474,143	5,818,068	SOUTHIMP	INTERFACE	5,679,046	0	5,679,046
PPL	ZONE	176,810	4,895,847	5,072,657	IMO	INTERFACE	3,231,818	62,319	3,294,137
SOUTHIMP	INTERFACE	4,663,488	0	4,663,488	N ILLINOIS HUB	HUB	720,127	2,168,438	2,888,565
PECO	ZONE	216,176	4,185,369	4,401,545	NYIS	INTERFACE	1,431,944	298,458	1,730,402
AEP-DAYTON HUB	HUB	1,802,533	1,887,976	3,690,509	BGE	ZONE	151,715	1,071,700	1,223,414
IMO	INTERFACE	3,198,562	172,008	3,370,570	MISO	INTERFACE	318,614	852,233	1,170,846
N ILLINOIS HUB	HUB	763,057	2,005,553	2,768,610	LINDENVFT	INTERFACE	242,773	772,645	1,015,418
BGE	ZONE	19,928	2,315,050	2,334,978	BAGLEY 34 KV 230-1LD	LOAD	287,394	654,883	942,277
MIAMIFOR22 KV MI7	GEN	0	1,096,814	1,096,814	AEP-DAYTON HUB	HUB	445,332	492,832	938,165
Top ten total		21,078,651	32,896,588	53,975,239			27,047,631	22,946,897	49,994,527
PJM total		31,530,387	58,223,482	89,753,868			46,135,747	45,483,748	91,619,495
Top ten total as percent of PJM total		66.9%	56.5%	60.1%			58.6%	50.5%	54.6%

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Table 3-42 shows up to congestion transactions by import bids for the top ten locations for the first nine months of 2014 and 2015.[52]

Table 3-43 shows up to congestion transactions by export bids for the top ten locations for the first nine months of 2014 and 2015.

Table 3-42 PJM cleared up to congestion import bids by top ten source and sink pairs (MW): January through September 2014 and 2015

		2014 (Jan-Sep)		
		Imports		
Source	Source Type	Sink	Sink Type	MW
HUDSONTP	INTERFACE	LEONIA 230 T-2	AGGREGATE	963,202
SOUTHEAST	INTERFACE	EDANVILL T1	AGGREGATE	759,991
MISO	INTERFACE	COOK	EHVAGG	622,425
OVEC	INTERFACE	BIG SANDY CT1	AGGREGATE	586,825
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	494,223
NEPTUNE	INTERFACE	SOUTHRIV 230	AGGREGATE	428,548
MISO	INTERFACE	AEP-DAYTON HUB	HUB	425,824
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	395,037
OVEC	INTERFACE	DEOK	ZONE	374,463
HUDSONTP	INTERFACE	LEONIA 230 T-1	AGGREGATE	374,309
Top ten total				5,424,846
PJM total				26,612,297
Top ten total as percent of PJM total				20.4%
		2015 (Jan-Sep)		
		Imports		
Source	Source Type	Sink	Sink Type	MW
SOUTHIMP	INTERFACE	NAGELAEP	EHVAGG	1,460,129
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	403,758
OVEC	INTERFACE	AEP-DAYTON HUB	HUB	339,818
SOUTHEAST	INTERFACE	HALIFXDP TX1	AGGREGATE	324,306
SOUTHIMP	INTERFACE	WOLF HILLS 1-5	AGGREGATE	317,353
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	316,716
NORTHWEST	INTERFACE	COMED	ZONE	281,716
SOUTHEAST	INTERFACE	DOM	ZONE	225,221
SOUTHEAST	INTERFACE	NAGELAEP	EHVAGG	220,198
MISO	INTERFACE	21 KINCA ATR24304	AGGREGATE	213,006
Top ten total				4,102,221
PJM total				15,137,682
Top ten total as percent of PJM total				27.1%

Table 3-43 PJM cleared up to congestion export bids by top ten source and sink pairs (MW): January through September 2014 and 2015

		2014 (Jan-Sep)		
		Exports		
Source	Source Type	Sink	Sink Type	MW
JEFFERSON	EHVAGG	OVEC	INTERFACE	2,072,977
TANNERS CRK 4	AGGREGATE	SOUTHWEST	INTERFACE	1,679,588
TANNERS CRK 4	AGGREGATE	OVEC	INTERFACE	809,364
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	664,629
ROCKPORT	EHVAGG	OVEC	INTERFACE	538,276
JEFFERSON	EHVAGG	SOUTHWEST	INTERFACE	529,406
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	509,420
BECKJORD 6	AGGREGATE	OVEC	INTERFACE	412,660
UNIV PARK 1-6	AGGREGATE	NIPSCO	INTERFACE	410,784
LINDEN A	AGGREGATE	LINDENVFT	INTERFACE	397,470
Top ten total				8,024,571
PJM total				28,342,066
Top ten total as percent of PJM total				28.3%
		2015 (Jan-Sep)		
		Exports		
Source	Source Type	Sink	Sink Type	MW
FOWLER RIDGE II WF	AGGREGATE	SOUTHWEST	INTERFACE	343,253
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	218,545
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	181,832
21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	169,201
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	163,635
COMED	ZONE	NIPSCO	INTERFACE	159,882
SULLIVAN-AEP	EHVAGG	SOUTHWEST	INTERFACE	156,253
SULLIVAN-AEP	EHVAGG	NORTHWEST	INTERFACE	119,532
JCPL	ZONE	NEPTUNE	INTERFACE	113,174
FOWLER 34.5 KV FWLR1AWF	AGGREGATE	SOUTHWEST	INTERFACE	106,712
Top ten total				1,732,019
PJM total				6,327,516
Top ten total as percent of PJM total				27.4%

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

Table 3-44 shows up to congestion transactions by wheel bids for the top ten locations for the first nine months of 2014 and 2015.

Table 3-44 PJM cleared up to congestion wheel bids by top ten source and sink pairs (MW): January through September 2014 and 2015

2014 (Jan-Sep)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
NORTHWEST	INTERFACE	MISO	INTERFACE	757,535
OVEC	INTERFACE	SOUTHEXP	INTERFACE	325,617
MISO	INTERFACE	NORTHWEST	INTERFACE	281,280
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	255,598
MISO	INTERFACE	NIPSCO	INTERFACE	113,990
NYIS	INTERFACE	IMO	INTERFACE	96,976
MISO	INTERFACE	SOUTHEXP	INTERFACE	94,359
IMO	INTERFACE	NYIS	INTERFACE	89,107
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	84,922
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	71,560
Top ten total				2,170,943
PJM total				2,760,951
Top ten total as percent of PJM total				78.6%
2015 (Jan-Sep)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	332,264
MISO	INTERFACE	NIPSCO	INTERFACE	177,329
NORTHWEST	INTERFACE	MISO	INTERFACE	135,300
NYIS	INTERFACE	IMO	INTERFACE	92,406
IMO	INTERFACE	NYIS	INTERFACE	84,814
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	33,446
SOUTHWEST	INTERFACE	IMO	INTERFACE	32,852
NIPSCO	INTERFACE	IMO	INTERFACE	27,238
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	19,661
SOUTHWEST	INTERFACE	OVEC	INTERFACE	18,072
Top ten total				953,381
PJM total				1,125,418
Top ten total as percent of PJM total				84.7%

On November 1, 2012, PJM eliminated the requirement for market participants to specify an interface pricing point as either the source or sink of an up to congestion transaction. The top ten internal up to congestion transaction locations were 9.6 percent of the PJM total internal up to congestion transactions in the first nine months of 2015.

Table 3-45 shows up to congestion transactions by internal bids for the top ten locations for the first nine months of 2014 and 2015.

Table 3-45 PJM cleared up to congestion internal bids by top ten source and sink pairs (MW): January through September 2014 and 2015

2014 (Jan-Sep)				
Internal				
Source	Source Type	Sink	Sink Type	MW
MOUNTAINEER	EHVAGG	GAVIN	EHVAGG	6,617,031
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	5,207,346
MOUNTAINEER	EHVAGG	FLATLICK	EHVAGG	4,294,621
ATSI GEN HUB	HUB	ATSI	ZONE	3,921,672
VERNON BK 4	AGGREGATE	AEC - JC	AGGREGATE	3,733,527
FE GEN	AGGREGATE	ATSI	ZONE	3,322,039
DUMONT	EHVAGG	COOK	EHVAGG	2,370,640
JEFFERSON	EHVAGG	COOK	EHVAGG	2,291,396
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	2,035,779
TANNERS CRK 4	AGGREGATE	STUART DIESEL	AGGREGATE	1,811,391
Top ten total				35,605,442
PJM total				350,877,067
Top ten total as percent of PJM total				10.1%
2015 (Jan-Sep)				
Internal				
Source	Source Type	Sink	Sink Type	MW
BERGEN 2CC	AGGREGATE	LEONIA 230 T-1	AGGREGATE	1,796,469
ROCKPORT	EHVAGG	JEFFERSON	EHVAGG	1,448,028
BYRON 1	AGGREGATE	ROCKFORD	AGGREGATE	1,277,083
JEFFERSON	EHVAGG	COOK	EHVAGG	865,473
BERGEN 2CC	AGGREGATE	LEONIA 230 T-2	AGGREGATE	799,241
MARYSVILLE	EHVAGG	MALISZEWSKI	EHVAGG	750,897
ATSI GEN HUB	HUB	ATSI	ZONE	647,987
PSEG	ZONE	WESTERN HUB	HUB	543,540
VALLEY	EHVAGG	DOOMS	EHVAGG	539,418
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	488,471
Top ten total				9,156,606
PJM total				95,518,327
Top ten total as percent of PJM total				9.6%

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Table 3-46 shows the number of source-sink pairs that were offered and cleared monthly in January of 2013 through September 2015. The annual row in Table 3-46 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 January 2013 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.[53]

Table 3-46 Number of PJM offered and cleared source and sink pairs: January 2013 through September 2015

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
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	10,614	5,690	7,570
2015	Jan	3,337	5,422	2,263	3,270
2015	Feb	4,600	7,041	2,775	4,147
2015	Mar	4,061	5,799	2,625	3,244
2015	Apr	3,777	6,967	2,343	3,378
2015	May	4,025	5,513	2,587	3,587
2015	Jun	3,852	5,967	2,781	3,748
2015	Jul	3,957	5,225	2,786	4,044
2015	Aug	4,996	6,143	3,702	4,378
2015	Sep	5,775	7,439	4,222	5,462
2015	Annual	4,259	6,152	2,897	3,912

53 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 3-47 and Figure 3-28 show total cleared up to congestion transactions by type for the first nine months of 2014 and 2015. Internal up to congestion transactions in the first nine months of 2015 were 80.9 percent of all up to congestion transactions compared to 85.9 percent in the first nine months of 2014.

Table 3-47 PJM cleared up to congestion transactions by type (MW): January through September 2014 and 2015

	2014 (Jan-Sep)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	5,424,846	8,024,571	2,170,943	35,605,442	51,225,802
PJM total (MW)	26,612,297	28,342,066	2,760,951	350,877,067	408,592,381
Top ten total as percent of PJM total	20.4%	28.3%	78.6%	10.1%	12.5%
PJM total as percent of all up-to congestion transactions	6.5%	6.9%	0.7%	85.9%	100.0%
	2015 (Jan-Sep)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	4,102,221	1,732,019	953,381	9,156,606	15,944,227
PJM total (MW)	15,137,682	6,327,516	1,125,418	95,518,327	118,108,943
Top ten total as percent of PJM total	27.1%	27.4%	84.7%	9.6%	13.5%
PJM total as percent of all up-to congestion transactions	12.8%	5.4%	1.0%	80.9%	100.0%

Figure 3-28 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.[54] Figure 3-29 shows the daily cleared up to congestion MW by transaction type for the period from January 2014 through September 2015 in order to show the drop off in UTC volumes compared to volumes in the last 21 months.

54 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 3-28 PJM monthly cleared up to congestion transactions by type (MW): January 2005 through September 2015

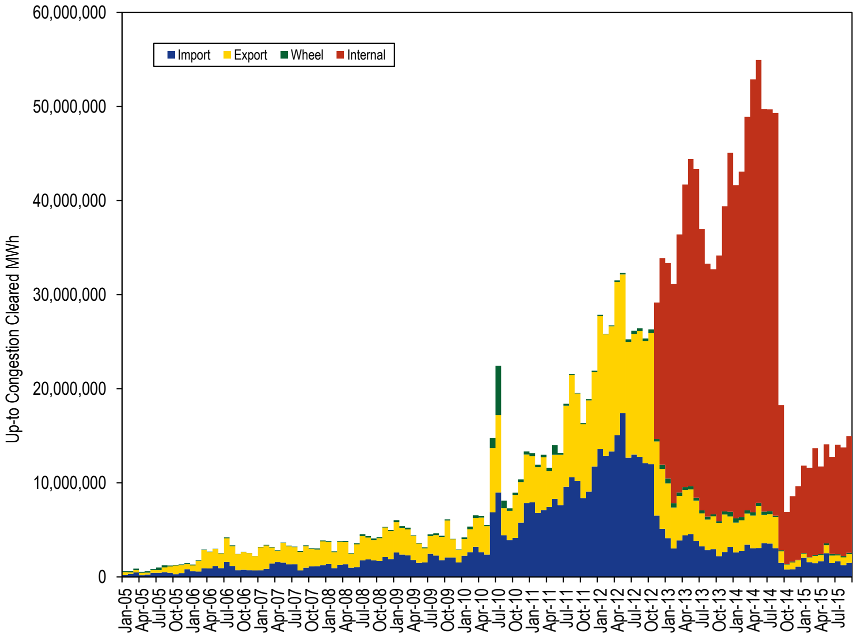
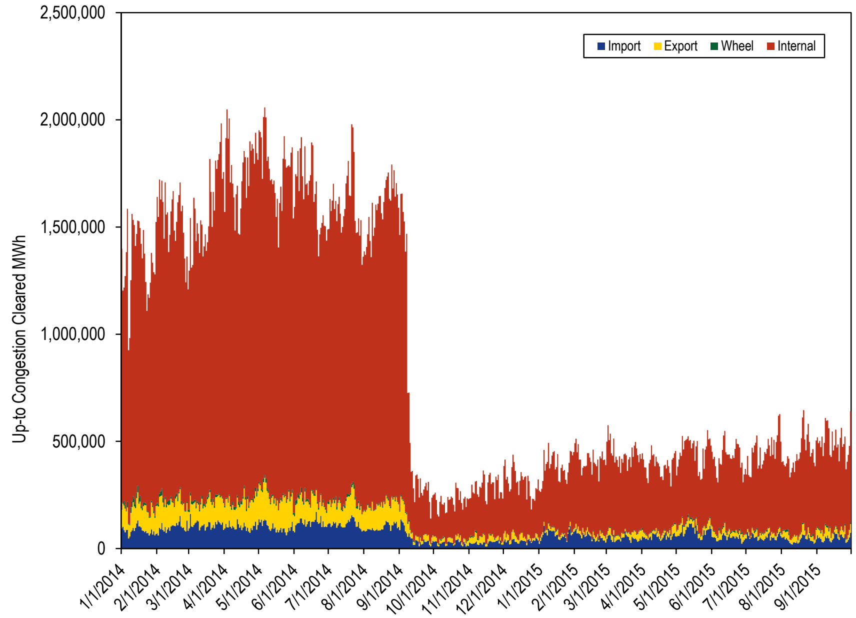


Figure 3-29 PJM daily cleared up to congestion transaction by type (MW): January 2014 through September 2015



Generator Offers

Generator offers are categorized as dispatchable (Table 3-48) or self scheduled (Table 3-49).[55] Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are self scheduled and must run. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are self scheduled and dispatchable. Table 3-48 and Table 3-49 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

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

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emergency maximum, are categorized as emergency MW. The emergency MW are included in both tables.

Table 3-48 shows the proportion of MW offers by dispatchable units, by unit type and by offer price range, for the first nine months of 2015. For example, 72.3 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, 80.8 percent of all CC MW offers were dispatchable, including the 6.0 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, 45.8 percent of all dispatchable offers were in the $0 to $200 per MWh price range. The total column in the all dispatchable offers row is the proportion of all MW offers that were offered as available for economic dispatch, including emergency MW. Among all the generator offers in the first nine months of 2015, 51.1 percent were offered as available for economic dispatch.

Table 3-48 Distribution of MW for dispatchable unit offer prices: January through September 2015

	Dispatchable (Range)							
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	0.2%	72.3%	1.4%	0.4%	0.5%	0.0%	6.0%	80.8%
CT	0.1%	73.3%	12.3%	1.5%	1.1%	0.1%	10.5%	99.0%
Diesel	5.3%	27.0%	20.0%	7.8%	1.2%	0.5%	12.9%	74.7%
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	6.8%	0.0%	0.0%	0.0%	0.0%	0.1%	6.8%
Pumped Storage	28.3%	26.9%	0.0%	0.0%	0.0%	0.0%	14.1%	69.3%
Run of River	0.2%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%
Solar	6.5%	7.6%	0.0%	0.0%	0.0%	0.0%	2.4%	16.5%
Steam	0.0%	45.8%	1.4%	0.1%	0.1%	0.0%	2.6%	49.9%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	48.6%	11.2%	0.0%	0.0%	0.0%	0.0%	0.6%	60.5%
All Dispatchable Offers	1.5%	45.8%	3.1%	0.4%	0.3%	0.0%	4.4%	55.5%

Table 3-49 shows the proportion of MW offers by unit type that were self scheduled to generate fixed output and by unit type and price range for self-scheduled and dispatchable units, for the first nine months of 2015. For example, 16.0 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, 19.2 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 1.0 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 23.4 percent of all offers and self-scheduled and dispatchable units accounted for 20.0 percent of all offers. The total column in the all self-scheduled offers row is the proportion of all MW offers that were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including emergency MW. Among all the generator offers in the first nine months of 2015, 23.4 percent were offered as self scheduled and 21.2 percent were offered as self scheduled and dispatchable.

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Table 3-49 Distribution of MW for self scheduled offer prices: January through June 2015

	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	1.3%	0.4%	0.2%	16.0%	0.1%	0.0%	0.1%	0.0%	1.0%	19.2%
CT	0.4%	0.1%	0.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%
Diesel	23.8%	1.1%	0.1%	0.2%	0.0%	0.0%	0.0%	0.0%	0.1%	25.3%
Fuel Cell	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Nuclear	91.9%	1.0%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	93.2%
Pumped Storage	14.7%	8.1%	3.5%	0.0%	0.0%	0.0%	0.0%	0.0%	4.5%	30.7%
Run of River	62.2%	8.7%	3.6%	18.4%	0.0%	0.0%	0.0%	4.2%	2.5%	99.6%
Solar	60.9%	22.2%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	83.5%
Steam	5.2%	1.4%	0.2%	41.2%	0.2%	0.0%	0.0%	0.0%	1.8%	50.1%
Transaction	74.4%	25.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	4.2%	2.7%	25.8%	2.9%	0.0%	0.0%	0.0%	0.0%	4.0%	39.5%
All Self-Scheduled Offers	22.2%	1.2%	0.6%	19.2%	0.1%	0.0%	0.0%	0.1%	1.1%	44.5%

Market Performance

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

Markup

The markup index, which is a measure of participant conduct for individual marginal units, does not measure the impact of participant behavior on market prices. As an example, if unit A has a $90 cost and a $100 price, while unit B has a $9 cost and a $10 price, both would show a markup of 10 percent, but the price impact of unit A's markup at the generator bus would be $10 while the price impact of unit B's markup at the generator bus would be $1. Depending on each unit's location on the transmission system, those bus-level impacts could also translate to different impacts on total system price.

The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of price based on a comparison between the price-based offer and the cost-based offer of each actual marginal unit on the system.[56]

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

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

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

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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 3-50 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 3-50 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 3-28.

All generating units, including coal units, are allowed to include a 10 percent adder in their cost offer. The 10 percent adder was included in the definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. Coal units do not face the same cost uncertainty as gas-fired CTs. A review of actual participant behavior supports this view, as the owners of coal units, facing competition, typically exclude the 10 percent adder from their actual offers. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the 10 percent adder in the cost offer. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder from the cost offer. Even the adjusted markup underestimates the markup because coal units facing increased competitive pressure have excluded both the ten percent adder and some or all components of operating and maintenance cost. While both these elements are permitted under the definition of cost-based offers in the relevant PJM manual, they are not part of a competitive offer for a coal unit because they are not actually marginal costs, and market behavior reflected that fact.[57]

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

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

Table 3-50 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 decreased from $3.62 in the first nine months of 2014 to $1.75 in the first nine months of 2015. The adjusted markup contribution of coal units in the first nine months of 2015 was $0.60. Although the price of natural gas was substantially lower in the first nine months of 2015 compared to that in 2014, the adjusted mark-up component of all gas-fired units in the first nine months of 2015 was $1.04, a decrease of $0.11 from the first nine months of 2014. Coal units accounted for 71.83 percent of the decreased markup component of LMP in the first nine months of 2015. 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 the first nine months of 2015, among the wind units that were marginal, 3.83 percent had positive offer prices.

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Table 3-50 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through September 2014 and 2015[58]

		2014 (Jan - Sep)		2015 (Jan - Sep)	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	$0.60	$1.94	($1.07)	$0.60
Gas	CC	$0.75	$0.75	$1.10	$1.10
Gas	CT	$0.32	$0.32	($0.11)	($0.11)
Gas	Diesel	$0.12	$0.12	$0.02	$0.02
Gas	Steam	($0.03)	($0.03)	$0.03	$0.03
Municipal Waste	Steam	$0.20	$0.20	($0.02)	($0.02)
Oil	CC	$0.12	$0.12	$0.06	$0.06
Oil	CT	$0.12	$0.12	$0.04	$0.04
Oil	Diesel	$0.00	$0.00	$0.00	$0.00
Oil	Steam	$0.05	$0.05	$0.03	$0.03
Other	Steam	($0.00)	($0.00)	($0.03)	($0.03)
Uranium	Steam	$0.01	$0.01	$0.00	$0.00
Wind	Wind	$0.04	$0.04	$0.03	$0.03
Total		$2.28	$3.62	$0.08	$1.75

Markup Component of Real-Time Price

Table 3-51 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on-peak and off-peak prices. Table 3-52 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on-peak and off-peak prices. In the first nine months of 2015, when using unadjusted cost offers, $0.08 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-offers, $1.75 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first nine months of 2015, the peak markup component was highest in February, $4.79 per MWh using unadjusted cost offers and $6.64 per MWh using adjusted cost offers. This corresponds to 8.85 percent and 12.27 percent of the real time load-weighted average LMP in February.

58 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.

Table 3-51 Monthly markup components of real-time load-weighted LMP (Unadjusted): January through September 2014 and 2015

	2014			2015		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$5.44	$3.91	$6.92	($1.42)	($2.55)	($0.31)
Feb	$3.02	$0.88	$5.08	$4.62	$4.46	$4.79
Mar	$7.11	$3.24	$11.17	$1.84	$1.82	$1.86
Apr	($0.43)	($2.16)	$1.07	($0.42)	($0.69)	($0.18)
May	$1.74	($1.27)	$4.62	($1.85)	($3.59)	($0.01)
Jun	$2.43	($0.08)	$4.60	($0.43)	($1.20)	$0.21
Jul	($0.15)	($1.22)	$0.77	($0.46)	($1.29)	$0.21
Aug	($1.08)	($1.91)	($0.29)	($0.90)	($0.96)	($0.83)
Sep	$1.51	($0.13)	$3.01	($0.55)	($0.64)	($0.47)
Total	$2.28	$0.31	$4.12	$0.08	($0.44)	$0.57

Table 3-52 Monthly markup components of real-time load-weighted LMP (Adjusted): January through September 2014 and 2015

	2014			2015		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$6.83	$5.48	$8.12	$0.61	($0.53)	$1.72
Feb	$3.94	$1.97	$5.84	$6.44	$6.26	$6.64
Mar	$8.21	$4.59	$12.02	$3.71	$3.69	$3.74
Apr	$0.86	($0.45)	$2.00	$1.22	$0.72	$1.65
May	$2.87	$0.09	$5.54	($0.45)	($2.41)	$1.64
Jun	$3.69	$1.46	$5.62	$1.18	$0.06	$2.10
Jul	$1.48	$0.35	$2.44	$1.17	$0.16	$1.97
Aug	$0.50	($0.29)	$1.25	$0.65	$0.43	$0.86
Sep	$3.18	$1.65	$4.59	$0.88	$0.71	$1.03
Total	$3.61	$1.81	$5.30	$1.75	$1.10	$2.36

Hourly Markup Component of Real-Time Prices

Figure 3-30 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers for the first nine months of 2015 and the first nine months of 2014. Figure 3-31 shows the markup contribution to the hourly load-weighted LMP using adjusted cost offers for the first nine months of 2015 and the first nine months of 2014. In 2014, high markups

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were seen during the polar vortex events in January and early March. In contrast, January 2015 had very low markups. Most high markup hours in 2015 were observed in February and March.

Figure 3-30 Markup Contribution to real-time hourly load-weighted LMP (Unadjusted): January through September 2014 and 2015

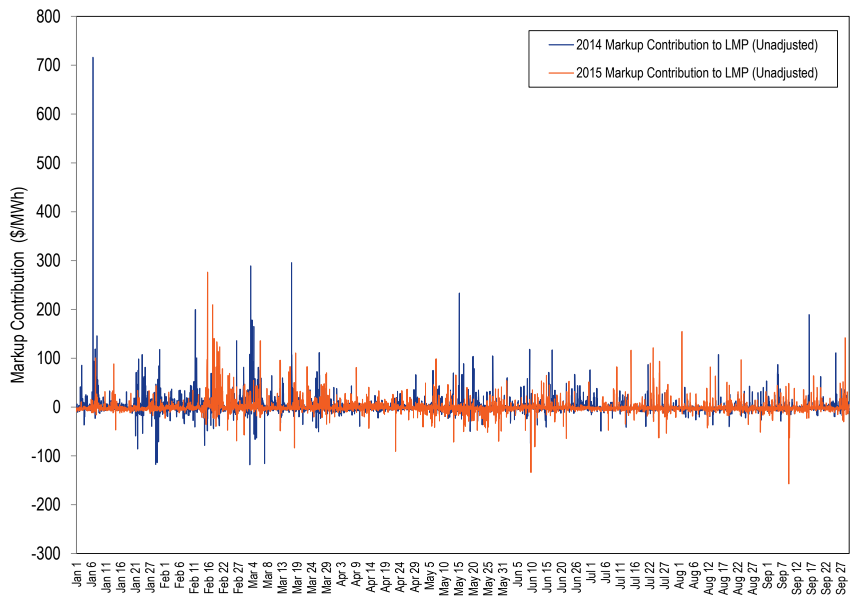
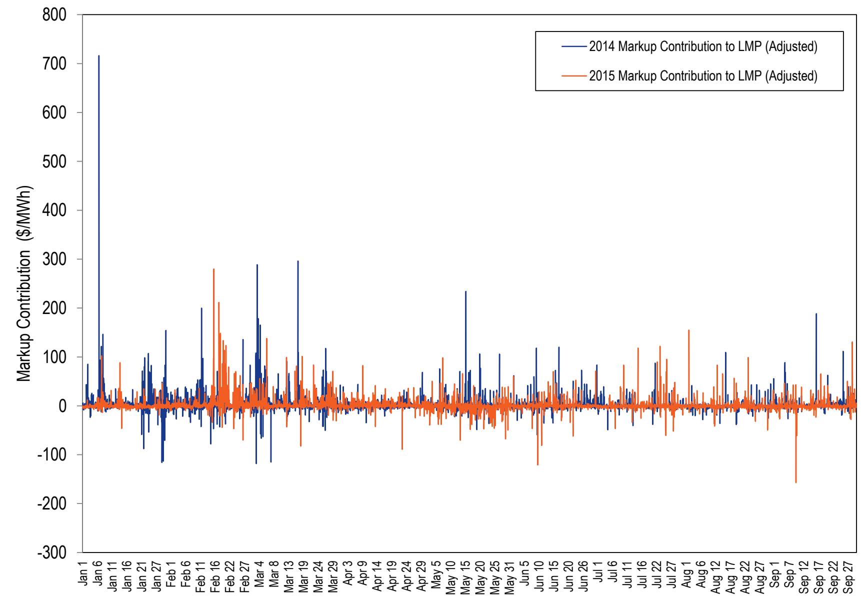


Figure 3-31 Markup Contribution to real-time hourly load-weighted LMP (Adjusted): January through September 2014 and 2015



Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone for the first nine months of 2014 and 2015 in Table 3-53 and for adjusted offers in Table 3-54. The smallest zonal all hours average markup component using unadjusted offers for the first nine months of 2015 was in the AECO Zone, -$0.78 per MWh, while the highest was in the BGE Control Zone, $1.72 per MWh. The smallest zonal on peak average markup was in the DPL Control Zone, -$0.54 per MWh, while the highest was in the BGE Control Zone, $1.87 per MWh.

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Table 3-53 Average real-time zonal markup component (Unadjusted): January through September 2014 and 2015

	2014 (Jan - Sep)			2015 (Jan - Sep)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$2.18	($0.02)	$4.26	($0.78)	($1.20)	($0.38)
AEP	$1.87	($0.06)	$3.71	($0.08)	($0.80)	$0.61
APS	$2.04	$0.32	$3.67	$0.59	$0.14	$1.03
ATSI	$1.53	($0.22)	$3.17	($0.08)	($0.74)	$0.54
BGE	$3.71	$1.46	$5.81	$1.72	$1.56	$1.87
ComEd	$1.35	($0.21)	$2.80	($0.34)	($0.97)	$0.22
DAY	$1.62	($0.27)	$3.34	$0.02	($0.83)	$0.81
DEOK	$1.59	($0.38)	$3.43	($0.02)	($1.00)	$0.89
DLCO	$1.59	$0.08	$3.00	($0.26)	($1.05)	$0.48
DPL	$2.73	$0.68	$4.63	($0.57)	($0.60)	($0.54)
Dominion	$3.77	$1.35	$6.02	$0.77	$0.54	$0.99
EKPC	$2.00	$0.21	$3.76	($0.08)	($1.02)	$0.86
JCPL	$1.87	($0.04)	$3.55	($0.65)	($1.00)	($0.34)
Met-Ed	$1.98	$0.23	$3.57	($0.55)	($1.07)	($0.08)
PECO	$2.28	$0.26	$4.14	($0.69)	($1.05)	($0.36)
PENELEC	$2.38	$0.20	$4.39	$0.22	($0.46)	$0.86
PPL	$2.58	$0.36	$4.62	($0.24)	($0.48)	($0.02)
PSEG	$2.68	$0.44	$4.71	($0.15)	($0.86)	$0.49
Pepco	$3.47	$1.27	$5.47	$1.25	$0.84	$1.64
RECO	$2.63	$0.59	$4.35	$0.13	($1.11)	$1.18

Table 3-54 Average real-time zonal markup component (Adjusted): January through September 2014 and 2015

	2014 (Jan - Sep)			2015 (Jan - Sep)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$3.42	$1.28	$5.43	$0.45	($0.02)	$0.89
AEP	$3.25	$1.53	$4.89	$1.69	$0.82	$2.52
APS	$3.38	$1.82	$4.86	$2.37	$1.78	$2.94
ATSI	$2.90	$1.34	$4.37	$1.70	$0.90	$2.44
BGE	$5.29	$3.25	$7.19	$4.08	$3.66	$4.48
ComEd	$2.70	$1.33	$3.98	$1.23	$0.45	$1.94
DAY	$3.04	$1.35	$4.59	$1.84	$0.80	$2.79
DEOK	$2.96	$1.19	$4.63	$1.73	$0.59	$2.80
DLCO	$3.01	$1.68	$4.26	$1.48	$0.57	$2.33
DPL	$3.91	$1.97	$5.72	$0.73	$0.65	$0.81
Dominion	$5.13	$2.88	$7.23	$2.73	$2.34	$3.10
EKPC	$3.37	$1.77	$4.93	$1.67	$0.62	$2.71
JCPL	$3.06	$1.28	$4.63	$0.56	$0.16	$0.91
Met-Ed	$3.13	$1.53	$4.60	$0.66	$0.10	$1.17
PECO	$3.46	$1.57	$5.20	$0.51	$0.13	$0.86
PENELEC	$3.65	$1.61	$5.54	$1.80	$1.01	$2.53
PPL	$3.74	$1.66	$5.66	$0.97	$0.70	$1.22
PSEG	$3.87	$1.73	$5.81	$1.17	$0.39	$1.88
Pepco	$4.94	$2.94	$6.76	$3.39	$2.75	$3.97
RECO	$3.89	$1.90	$5.56	$1.61	$0.32	$2.68

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Markup by Real Time Price Levels

Table 3-55 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 3-55 Average real-time markup component (By price category, unadjusted): January through September 2014 and 2015

	2014 (Jan - Sep)		2015 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$0.41	67.8%	($0.10)	82.8%
$25 to $50	($0.19)	16.7%	($0.38)	14.4%
$50 to $75	$0.22	6.7%	$0.25	1.8%
$75 to $100	$0.23	2.5%	$0.07	0.5%
$100 to $125	$0.12	1.4%	$0.15	0.2%
$125 to $150	$0.20	1.1%	$0.05	0.1%
>= $150	$1.33	3.8%	$0.05	0.1%

Table 3-56 Average real-time markup component (By price category, adjusted): January through September 2014 and 2015

	2014 (Jan - Sep)		2015 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$1.35	67.8%	$1.25	82.8%
$25 to $50	$0.07	16.7%	($0.08)	14.4%
$50 to $75	$0.27	6.7%	$0.27	1.8%
$75 to $100	$0.26	2.5%	$0.07	0.5%
$100 to $125	$0.13	1.4%	$0.15	0.2%
$125 to $150	$0.21	1.1%	$0.05	0.1%
>= $150	$1.38	3.8%	$0.05	0.1%

Day-Ahead Markup

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

The markup component of the PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 3-57. INC, DEC and up to congestion transactions have zero markups. Up to congestion transactions were marginal for 76.5 percent of marginal resources in the first nine months of 2015. INCs were marginal for 4.9 percent of marginal resources and DECs were marginal for 8.6 percent of marginal resources in the first nine months of 2015. 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.[59] 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 3-57 shows the markup component of LMP for marginal generating resources. Generating resources were marginal in only 9.7 percent of marginal resources in the first nine months of 2015. The markup component of LMP for marginal generating resources decreased in coal-fired steam units and oil-fired CT units. The markup component of LMP for coal units decreased from $1.11 in the first nine months of 2014 to $0.33 in the first nine months of 2015 using adjusted offers. The markup component of LMP for gas-fired CCs increased from -$0.22 in the first nine months of 2014 to $0.49 in the first nine months of 2015 using adjusted offers.

59 See 18 CFR § 385.213 (2014).

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Table 3-57 Markup component of the annual PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through September of 2014 and 2015

		2014 (Jan - Sep)		2015 (Jan - Sep)	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($0.12)	$1.11	($0.31)	$0.33
Gas	CC	($0.22)	($0.22)	$0.49	$0.49
Gas	CT	$0.03	$0.03	$0.09	$0.09
Gas	Diesel	$0.00	$0.00	$0.03	$0.03
Gas	Steam	($0.04)	($0.04)	($0.31)	($0.31)
Municipal Waste	Steam	($0.00)	($0.00)	($0.00)	($0.00)
Oil	CC	$0.03	$0.03	$0.04	$0.04
Oil	CT	$0.04	$0.05	$0.02	$0.02
Oil	Diesel	$0.00	$0.00	$0.00	$0.00
Oil	Steam	$0.02	$0.02	$0.09	$0.09
Other	Steam	$0.00	$0.00	($0.00)	($0.00)
Wind	Wind	$0.03	$0.03	$0.04	$0.04
Total		($0.23)	$1.01	$0.17	$0.81

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 3-58 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted offers. Table 3-59 shows the markup component of average prices and of average monthly on-peak and off-peak prices using adjusted offers. In the first nine months of 2015, when using adjusted cost-offers, $0.81 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first nine months of 2015, the peak markup component was highest in February, $4.24 per MWh using adjusted cost offers. Using adjusted cost-offers, the markup component in the first nine months of 2015 decreased in every month except February, May and June from the first nine months of 2014. The markup component decreased from $1.79 to -$0.29 in January.

Table 3-58 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January through September of 2014 and 2015

	2014			2015		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	$1.03	$2.85	($0.88)	($1.98)	($1.27)	($2.66)
Feb	$0.34	$2.07	($1.47)	$1.39	$3.17	($0.24)
Mar	$0.14	($0.27)	$0.53	($0.43)	$0.49	($1.38)
Apr	($0.88)	$0.42	($2.37)	($0.77)	($0.02)	($1.63)
May	($0.99)	$0.07	($2.10)	$0.75	$0.70	$0.80
Jun	$0.03	$1.29	($1.45)	$1.66	$2.32	$0.85
Jul	($0.98)	($0.38)	($1.68)	($0.17)	$0.71	($1.28)
Aug	($0.70)	$0.07	($1.51)	$0.25	$1.05	($0.59)
Sep	($0.37)	$0.79	($1.64)	$0.92	$1.36	$0.43
Annual	($0.23)	$0.80	($1.34)	$0.17	$0.96	($0.67)

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Table 3-59 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: January through September of 2014 and 2015

	2014			2015		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	$1.79	$3.41	$0.09	($0.29)	$0.21	($0.76)
Feb	$1.42	$2.84	($0.07)	$2.73	$4.24	$1.32
Mar	$1.31	$0.61	$1.98	$1.01	$1.79	$0.21
Apr	$0.51	$1.34	($0.45)	$0.50	$1.02	($0.11)
May	$0.23	$0.85	($0.41)	$0.75	$0.70	$0.80
Jun	$1.37	$2.30	$0.29	$1.66	$2.32	$0.85
Jul	$0.52	$0.92	$0.05	($0.17)	$0.71	($1.28)
Aug	$0.64	$1.23	$0.01	$0.25	$1.05	($0.59)
Sep	$1.04	$1.94	$0.05	$0.92	$1.36	$0.43
Annual	$1.01	$1.75	$0.20	$0.81	$1.49	$0.09

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 3-60. The markup component of annual average day-ahead price using adjusted offers is shown for each zone in Table 3-61. The markup component of the average day-ahead price decreased in all zones from the first nine months of 2014 to the first nine months of 2015. The smallest zonal all hours average markup component using adjusted offers for the first nine months of 2015 was in the BGE Zone, $0.18 per MWh, while the highest was in the AECO Control Zone, $1.63 per MWh. The smallest zonal on peak average markup was in the BGE Control Zone, $0.10 per MWh, while the highest was in the AECO Control Zone, $3.04 per MWh.

Table 3-60 Day-ahead, average, zonal markup component (Unadjusted): January through September of 2014 and 2015

	2014 (Jan - Sep)			2015 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.06)	$1.03	($1.26)	$1.13	$2.63	($0.49)
AEP	($0.28)	$0.76	($1.37)	$0.09	$0.96	($0.81)
AP	($0.29)	$0.82	($1.47)	($0.02)	$0.49	($0.55)
ATSI	($0.32)	$0.75	($1.48)	($0.10)	$0.70	($0.96)
BGE	($0.12)	$0.95	($1.30)	($0.49)	($0.45)	($0.53)
ComEd	($0.31)	$0.51	($1.20)	$0.06	$1.05	($1.02)
DAY	($0.28)	$0.75	($1.40)	$0.00	$0.92	($1.00)
DEOK	($0.28)	$0.70	($1.31)	$0.05	$0.87	($0.82)
DLCO	($0.32)	$0.62	($1.36)	($0.23)	$0.46	($0.98)
Dominion	($0.26)	$0.79	($1.40)	$0.14	$0.55	($0.30)
DPL	($0.47)	$0.18	($1.19)	$0.91	$2.31	($0.59)
EKPC	($0.11)	$0.86	($1.11)	$0.20	$1.18	($0.79)
JCPL	($0.09)	$0.97	($1.31)	$0.75	$1.83	($0.49)
Met-Ed	($0.01)	$1.15	($1.29)	$0.11	$0.68	($0.52)
PECO	$0.02	$1.19	($1.25)	$0.60	$1.60	($0.49)
PENELEC	($0.26)	$0.82	($1.48)	$0.12	$0.80	($0.59)
Pepco	($0.11)	$0.98	($1.34)	$0.19	$0.88	($0.55)
PPL	($0.08)	$1.10	($1.35)	$0.37	$1.26	($0.59)
PSEG	($0.06)	$1.06	($1.34)	$0.79	$1.91	($0.46)
RECO	($0.07)	$1.02	($1.36)	$0.81	$1.87	($0.45)

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Table 3-61 Day-ahead, average, zonal markup component (Adjusted): January through September of 2014 and 2015

	2014 (Jan - Sep)			2015 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	$1.12	$1.93	$0.24	$1.63	$3.04	$0.11
AEP	$0.99	$1.72	$0.21	$0.79	$1.54	$0.02
AP	$0.94	$1.75	$0.08	$0.67	$1.08	$0.25
ATSI	$0.94	$1.71	$0.12	$0.64	$1.33	($0.11)
BGE	$1.22	$2.00	$0.37	$0.18	$0.10	$0.27
ComEd	$0.94	$1.48	$0.35	$0.73	$1.63	($0.24)
DAY	$1.01	$1.73	$0.22	$0.72	$1.51	($0.15)
DEOK	$0.98	$1.66	$0.27	$0.73	$1.44	($0.01)
DLCO	$0.90	$1.54	$0.21	$0.45	$1.04	($0.18)
Dominion	$0.98	$1.76	$0.15	$0.77	$1.07	$0.44
DPL	$0.69	$1.07	$0.28	$1.43	$2.72	$0.07
EKPC	$1.09	$1.76	$0.41	$0.92	$1.75	$0.09
JCPL	$1.11	$1.91	$0.19	$1.27	$2.26	$0.14
Met-Ed	$1.16	$2.04	$0.18	$0.65	$1.13	$0.14
PECO	$1.17	$2.06	$0.22	$1.11	$2.02	$0.13
PENELEC	$0.94	$1.76	$0.03	$0.75	$1.29	$0.18
Pepco	$1.19	$1.99	$0.28	$0.84	$1.43	$0.21
PPL	$1.08	$1.98	$0.10	$0.94	$1.73	$0.10
PSEG	$1.08	$1.95	$0.10	$1.29	$2.31	$0.15
RECO	$1.06	$1.91	$0.05	$1.30	$2.28	$0.15

Markup by Day-Ahead Price Levels

Table 3-62 and Table 3-63 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 3-62 Average, day-ahead markup (By LMP category, unadjusted): January through September of 2014 and 2015

	2014 (Jan - Sep)		2015 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($2.71)	9.2%	($1.18)	25.4%
$25 to $50	($1.33)	66.9%	($0.11)	61.7%
$50 to $75	$1.22	14.9%	$3.03	6.7%
$75 to $100	($1.01)	3.1%	($2.20)	3.1%
$100 to $125	($7.10)	1.1%	$1.16	1.5%
$125 to $150	$5.79	0.9%	$10.37	0.7%
>= $150	$10.52	3.8%	$12.53	0.9%

Table 3-63 Average, day-ahead markup (By LMP category, adjusted): January through September 2014 and 2015

	2014 (Jan - Sep)		2015 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($1.17)	9.2%	($0.87)	25.4%
$25 to $50	$0.51	66.9%	$0.82	61.7%
$50 to $75	$2.33	14.9%	$3.59	6.7%
$75 to $100	($0.57)	3.1%	($1.63)	3.1%
$100 to $125	($6.62)	1.1%	$1.73	1.5%
$125 to $150	$6.23	0.9%	$10.61	0.7%
>= $150	$11.42	3.8%	$12.75	0.9%

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 33.5 percent and 33.1 percent lower in the first nine months of 2015 than in the first nine months of 2014 as a result of lower fuel costs and lower demand in the first nine months of 2015. Coal and natural gas prices

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decreased in 2015. Comparing fuel prices in the first nine months of 2015 to the first nine months of 2014, the price of Northern Appalachian coal was 19.6 percent lower; the price of Central Appalachian coal was 22.9 percent lower; the price of Powder River Basin coal was 12.0 percent lower; the price of eastern natural gas was 42.3 percent lower; and the price of western natural gas was 50.0 percent lower

PJM real-time energy market prices decreased in the first nine months of 2015 compared to the first nine months of 2014. The average LMP was 31.8 percent lower in the first nine months of 2015 than in the first nine months of 2014, $35.96 per MWh versus $52.72 per MWh. The load-weighted average LMP was 33.5 percent lower in the first nine months of 2015 than in the first nine months of 2014, $38.94 per MWh versus $58.60 per MWh.

The fuel-cost adjusted, load-weighted, average LMP in the first nine months of 2015 was 14.8 percent higher than the load-weighted, average LMP for the first nine months of 2015. If fuel costs in the first nine months of 2015 had been the same as in the first nine months of 2014, holding everything else constant, the load-weighted LMP would have been higher, $44.72 per MWh instead of the observed $38.94 per MWh.

PJM day-ahead energy market prices decreased in the first nine months of 2015 compared to the first nine months of 2014. The average LMP was 31.8 percent lower in the first nine months of 2015 than in the first nine months of 2014, $36.67 per MWh versus $53.76 per MWh. The day-ahead load-weighted average LMP was 33.1 percent lower in the first nine months of 2015 than in the first nine months of 2014, $39.51 per MWh versus $59.09 per MWh.[60]

Occasionally, in a constrained market, the LMPs at some pricing nodes can exceed the offer price of the highest cleared generator in the supply stack.[61] In the nodal pricing system, the LMP at a pricing node is the total cost of meeting incremental demand at that node. When there are binding transmission constraints, satisfying the marginal increase in demand at a node may require increasing the output of some generators while simultaneously decreasing the output of other generators, such that the transmission constraints are not violated. The total cost of redispatching multiple generators can at times exceed the cost of marginally increasing the output of the most expensive generator offered. Thus occasionally the LMPs at some pricing nodes exceed $1,000 per MWh, the cap on the generators' offer price in the PJM market.[62]

Real-Time LMP

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

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 3-32 shows the hourly distribution of PJM real-time average LMP for the first nine months of 2014 and 2015. In the first nine months of 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 than $1,800.

60 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."

61 See O'Neill R. P, Mead D. and Malvadkar P. "On Market Clearing Prices Higher than the Highest Bid and Other Almost Paranormal Phenomena." *The Electricity Journal* 2005; 18(2): pp 19-27.

62 The offer cap in PJM was temporarily increased to $1,800 per MWh prior to the winter of 2014/2015.

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

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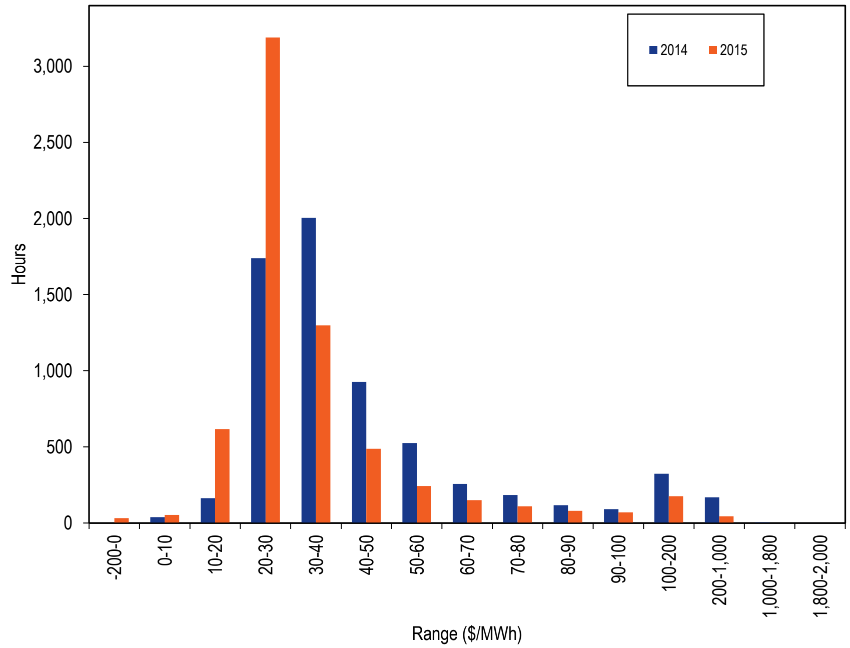
Figure 3-32 Average LMP for the PJM Real-Time Energy Market: January through September 2014 and 2015[64]



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

PJM Real-Time, Average LMP

Table 3-64 shows the PJM real-time, average LMP for the first nine months of each year of the 18 year period 1998 to 2015.[65]

Table 3-64 PJM real-time, average LMP (Dollars per MWh): January through September of 1998 through 2015

	Real-Time LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$23.18	$16.86	$36.00	NA	NA	NA
1999	$31.65	$18.77	$83.28	36.6%	11.3%	131.3%
2000	$25.88	$18.22	$23.70	(18.2%)	(2.9%)	(71.5%)
2001	$36.00	$25.48	$51.30	39.1%	39.9%	116.4%
2002	$28.13	$20.70	$23.92	(21.9%)	(18.8%)	(53.4%)
2003	$40.42	$33.68	$26.00	43.7%	62.7%	8.7%
2004	$43.85	$39.99	$21.82	8.5%	18.7%	(16.1%)
2005	$54.69	$44.53	$33.67	24.7%	11.4%	54.3%
2006	$51.79	$43.50	$34.93	(5.3%)	(2.3%)	3.7%
2007	$57.34	$49.40	$35.52	10.7%	13.6%	1.7%
2008	$71.94	$61.33	$41.64	25.4%	24.2%	17.2%
2009	$37.42	$33.00	$17.92	(48.0%)	(46.2%)	(57.0%)
2010	$46.13	$37.89	$26.99	23.3%	14.8%	50.6%
2011	$45.79	$37.05	$32.25	(0.7%)	(2.2%)	19.5%
2012	$32.45	$28.78	$21.94	(29.1%)	(22.3%)	(32.0%)
2013	$37.30	$32.44	$22.84	15.0%	12.7%	4.1%
2014	$52.72	$36.06	$74.17	41.3%	11.2%	224.8%
2015	$35.96	$27.88	$30.75	(31.8%)	(22.7%)	(58.5%)

Real-Time, Load-Weighted, Average LMP

Higher demand (load) generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than average prices. Load-weighted LMP reflects the average LMP paid for actual MWh consumed during a year. Load-weighted, average LMP is the average of PJM hourly LMP, each weighted by the PJM total hourly load. The real-time, load-weighted, average LMP decreased by 33.5 percent compared to the first nine months of 2014.

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

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PJM Real-Time, Load-Weighted, Average LMP

Table 3-65 shows the PJM real-time, load-weighted, average LMP for the first nine months of each year of the 18 year period 1998 to 2015.

Table 3-65 PJM real-time, load-weighted, average LMP (Dollars per MWh): January through September of 1998 through 2015

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$26.06	$18.20	$44.65	NA	NA	NA
1999	$38.65	$20.02	$104.17	48.3%	10.0%	133.3%
2000	$28.49	$19.30	$26.89	(26.3%)	(3.6%)	(74.2%)
2001	$40.96	$28.18	$64.57	43.8%	46.0%	140.1%
2002	$31.95	$23.09	$29.14	(22.0%)	(18.1%)	(54.9%)
2003	$43.57	$38.17	$26.53	36.3%	65.3%	(9.0%)
2004	$46.44	$43.03	$21.89	6.6%	12.7%	(17.5%)
2005	$60.44	$50.10	$36.52	30.2%	16.4%	66.9%
2006	$56.39	$46.82	$40.70	(6.7%)	(6.5%)	11.4%
2007	$61.83	$55.12	$37.98	9.7%	17.7%	(6.7%)
2008	$77.27	$66.73	$43.80	25.0%	21.1%	15.3%
2009	$39.57	$34.57	$19.04	(48.8%)	(48.2%)	(56.5%)
2010	$49.91	$40.33	$29.65	26.2%	16.7%	55.7%
2011	$49.48	$38.72	$37.02	(0.9%)	(4.0%)	24.8%
2012	$35.02	$29.84	$25.44	(29.2%)	(22.9%)	(31.3%)
2013	$39.75	$33.61	$26.47	13.5%	12.6%	4.0%
2014	$58.60	$37.93	$86.22	47.4%	12.8%	225.8%
2015	$38.94	$29.09	$33.95	(33.5%)	(23.3%)	(60.6%)

Table 3-66 shows zonal real-time, and real-time, load-weighted, average LMP for the first nine months of 2014 and 2015.

Table 3-66 Zone real-time and real-time, load-weighted, average LMP (Dollars per MWh): January through September of 2014 and 2015

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2014 (Jan-Sep) Average	2015 (Jan-Sep) Average	Percentage Change	2014 (Jan-Sep) Average	2015 (Jan-Sep) Average	Percentage Change
AECO	$57.16	$36.72	(35.8%)	$62.02	$39.34	(36.6%)
AEP	$47.07	$33.54	(28.7%)	$51.76	$35.90	(30.6%)
AP	$51.93	$37.50	(27.8%)	$58.66	$41.17	(29.8%)
ATSI	$48.95	$34.02	(30.5%)	$52.74	$36.05	(31.6%)
BGE	$65.16	$45.50	(30.2%)	$75.84	$50.19	(33.8%)
ComEd	$41.98	$29.40	(30.0%)	$44.79	$31.18	(30.4%)
Day	$46.82	$33.76	(27.9%)	$51.13	$36.04	(29.5%)
DEOK	$44.57	$32.63	(26.8%)	$48.45	$34.89	(28.0%)
DLCO	$44.05	$32.06	(27.2%)	$47.04	$33.86	(28.0%)
Dominion	$60.29	$39.94	(33.8%)	$70.61	$44.52	(37.0%)
DPL	$44.05	$32.06	(27.2%)	$72.28	$46.00	(36.4%)
EKPC	$44.65	$31.57	(29.3%)	$52.51	$34.80	(33.7%)
JCPL	$56.96	$36.41	(36.1%)	$62.59	$39.64	(36.7%)
Met-Ed	$55.42	$36.13	(34.8%)	$63.19	$40.12	(36.5%)
PECO	$56.16	$35.71	(36.4%)	$62.83	$39.12	(37.7%)
PENELEC	$52.20	$36.73	(29.6%)	$57.50	$39.74	(30.9%)
Pepco	$63.85	$41.92	(34.3%)	$73.53	$45.93	(37.5%)
PPL	$55.46	$35.78	(35.5%)	$64.58	$40.34	(37.5%)
PSEG	$59.98	$39.01	(35.0%)	$64.49	$41.41	(35.8%)
RECO	$58.85	$39.63	(32.7%)	$62.69	$41.80	(33.3%)
PJM	$52.72	$35.96	(31.8%)	$58.60	$38.94	(33.5%)

Figure 3-33 is a contour map of the real-time, load-weighted, average LMP in the first nine months of 2015. 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 the first nine months of 2015.

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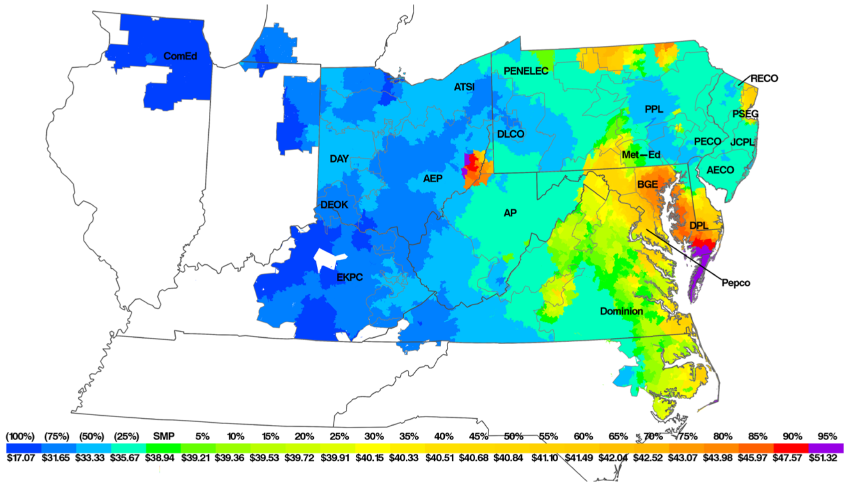
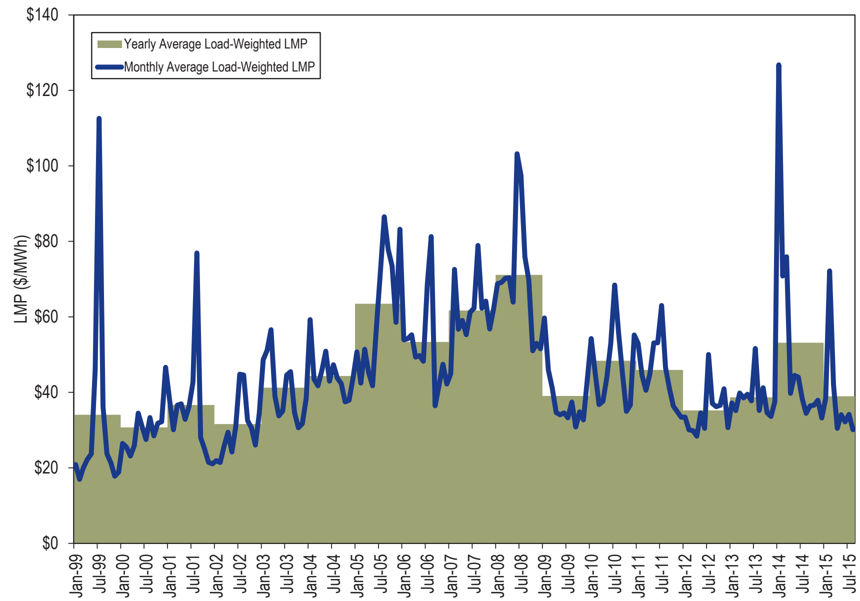
Figure 3-33 PJM real-time, load-weighted, average LMP: January through September 2015



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

Figure 3-34 shows the PJM real-time monthly and annual load-weighted LMP for the first nine months from 1999 through 2015.

Figure 3-34 PJM real-time, monthly and annual, load-weighted, average LMP: January 1999 through September 2015



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. Coal and natural gas prices decreased in 2015. Comparing fuel prices in 2015 to 2014, the price of Northern Appalachian coal was 19.6 percent lower; the price of Central Appalachian coal was 22.9 percent lower; the price of Powder River Basin coal was 12.0 percent lower; the price of eastern natural gas was 42.3 percent lower; and the price of western natural gas was 50.0 percent lower. Figure 3-35 shows monthly average spot fuel prices.[66]

Figure 3-35 Spot average fuel price comparison with fuel delivery charges: 2012 through September, 2015 ($/MMBtu)

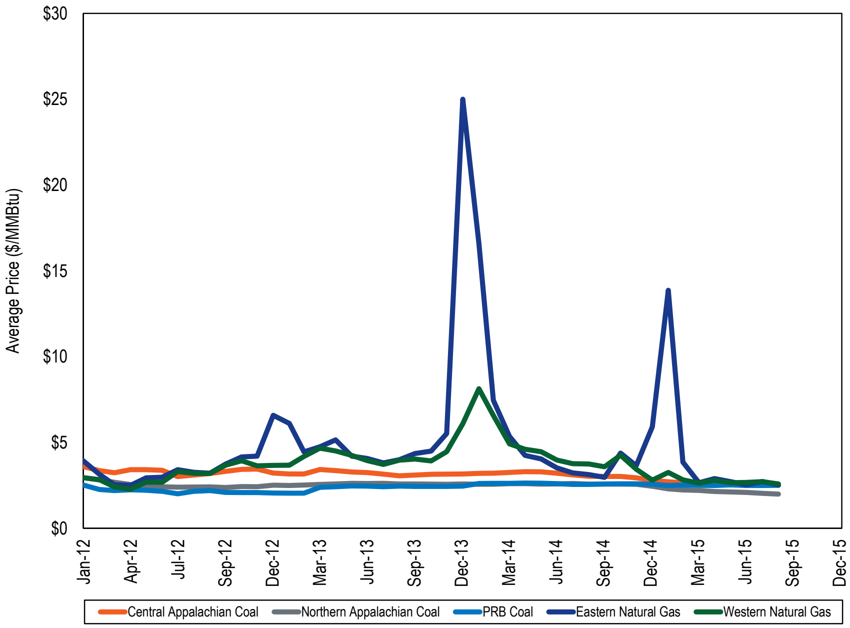


Table 3-67 compares the first nine months of 2015 PJM real time fuel-cost adjusted, load-weighted, average LMP to the first nine months of 2015 load-weighted, average LMP. The real time fuel-cost adjusted, load-weighted, average LMP for the first nine months of 2015 was 14.8 percent higher than the real time load-weighted, average LMP for the first nine months of 2015. The real-time, fuel-cost adjusted, load-weighted, average LMP for the first nine months of 2015 was 23.7 percent lower than the real time load-weighted LMP for the first nine months of 2014. If fuel costs in the first nine months of 2015 had been the same as in the first nine months of 2014, holding everything else constant, the real time load-weighted LMP in 2015 would have been higher, $44.72 per MWh instead of the observed $38.94 per MWh.

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

	2015 Load-Weighted LMP	2015 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$38.94	$44.72	14.8%
	2014 Load-Weighted LMP	2015 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$58.60	$44.72	(23.7%)
	2014 Load-Weighted LMP	2015 Load-Weighted LMP	Change
Average	$58.60	$38.94	(33.5%)

Table 3-68 shows the impact of each fuel type on the difference between the fuel-cost adjusted, load-weighted average LMP and the load-weighted LMP in the first nine months of 2015. Table 3-68 shows that lower coal, natural gas and oil prices explain almost all of the fuel-cost related decrease in the real time annual load-weighted average LMP in the first nine months of 2015. Unlike oil and natural gas, there was no substantial change in the price of coal from the first nine months of 2014 to the first nine months of 2015. However, coal units' offer prices were generally lower in the first nine months of 2015 compared to their offers in the first nine months of 2014, particularly the high offer prices during the cold weather days in January and March of 2014.

66 Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily fuel price indices. Western natural gas prices are the average of Dominion North Point, Columbia Appalachia and Chicago Citygate daily fuel price indices. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

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Table 3-68 Change in PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh) by Fuel-type: nine months over nine months

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Coal	($1.49)	25.8%
Gas	($3.67)	63.5%
Municipal Waste	($0.00)	0.0%
Oil	($0.60)	10.4%
Other	($0.02)	0.4%
Uranium	$0.00	(0.0%)
Wind	($0.00)	0.0%
Total	($5.78)	100.0%

Components of Real-Time, Load-Weighted LMP

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

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, emission rates for NO_x, emission rates for SO_2 and emission rates for CO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware and Maryland.[67] The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal.

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.[68] 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 3-69, including markup using unadjusted cost offers.[69] Table 3-69 shows that for the first nine months of 2015, 41.2 percent of the load-weighted LMP was the result of coal costs, 28.7 percent was the result of gas costs and 2.31 percent was the result of the cost of emission allowances. Markup was $0.08 per MWh. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP and does not reflect the other components of the offers of units burning that fuel. The component NA is the unexplainable portion of load-weighted LMP. Occasionally, PJM fails to provide all the data needed to accurately calculate generator sensitivity factors. As a result, the LMP for those intervals cannot be decomposed into component costs. The cumulative effect of excluding those five-minute intervals is the component NA. In the first nine months of 2015, nearly nine percent of all five-minute intervals had insufficient data. The percent column is the difference in the proportion of LMP represented by each component between the first nine months of 2015 and 2014.

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

68 PJM triggered shortage pricing on January 6, 2015, following a RTO-wide voltage reduction action. PJM triggered shortage pricing on January 7, 2014 due to RTO-wide shortage of synchronized reserve.

69 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 3-69 Components of PJM real-time (Unadjusted), nine month, load-weighted, average LMP: January through September 2014 and 2015

	2014 (Jan - Sep)		2015 (Jan - Sep)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Coal	$17.52	29.9%	$16.04	41.2%	11.3%
Gas	$21.56	36.8%	$11.19	28.7%	(8.1%)
Ten Percent Adder	$4.02	6.9%	$3.24	8.3%	1.5%
VOM	$2.75	4.7%	$2.51	6.4%	1.7%
Oil	$3.63	6.2%	$1.58	4.1%	(2.1%)
Ancillary Service Redispatch Cost	$0.57	1.0%	$1.18	3.0%	2.0%
NA	$1.97	3.4%	$1.03	2.6%	(0.7%)
LPA Rounding Difference	($0.07)	(0.1%)	$0.97	2.5%	2.6%
SO_2 Cost	$0.01	0.0%	$0.41	1.1%	1.0%
Increase Generation Adder	$0.87	1.5%	$0.29	0.7%	(0.7%)
CO_2 Cost	$0.22	0.4%	$0.25	0.6%	0.3%
NO_x Cost	$0.15	0.3%	$0.24	0.6%	0.4%
Other	$0.03	0.1%	$0.15	0.4%	0.3%
Markup	$2.28	3.9%	$0.08	0.2%	(3.7%)
Municipal Waste	$0.02	0.0%	$0.01	0.0%	0.0%
Market-to-Market Adder	($0.01)	(0.0%)	$0.01	0.0%	0.0%
FMU Adder	$0.76	1.3%	$0.00	0.0%	(1.3%)
Emergency DR Adder	$2.40	4.1%	$0.00	0.0%	(4.1%)
Scarcity Adder	$0.13	0.2%	$0.00	0.0%	(0.2%)
Constraint Violation Adder	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Uranium	($0.01)	(0.0%)	($0.00)	(0.0%)	0.0%
Decrease Generation Adder	($0.19)	(0.3%)	($0.06)	(0.2%)	0.2%
Wind	($0.01)	(0.0%)	($0.07)	(0.2%)	(0.2%)
LPA-SCED Differential	($0.01)	(0.0%)	($0.11)	(0.3%)	(0.3%)
Total	$58.60	100.0%	$38.94	100.0%	0.0%

Table 3-70 Components of PJM real-time (Adjusted), nine month, load-weighted, average LMP: January through September 2014 and 2015

	2014 (Jan - Sep)		2015 (Jan - Sep)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Coal	$17.52	29.9%	$16.04	41.2%	11.3%
Gas	$21.56	36.8%	$11.19	28.7%	(8.1%)
VOM	$2.75	4.7%	$2.51	6.4%	1.7%
Markup	$3.61	6.2%	$1.75	4.5%	(1.7%)
Oil	$3.63	6.2%	$1.58	4.1%	(2.1%)
Ten Percent Adder	$2.69	4.6%	$1.57	4.0%	(0.6%)
Ancillary Service Redispatch Cost	$0.57	1.0%	$1.18	3.0%	2.0%
NA	$1.97	3.4%	$1.03	2.6%	(0.7%)
LPA Rounding Difference	($0.07)	(0.1%)	$0.97	2.5%	2.6%
SO_2 Cost	$0.01	0.0%	$0.41	1.1%	1.0%
Increase Generation Adder	$0.87	1.5%	$0.29	0.7%	(0.7%)
CO_2 Cost	$0.22	0.4%	$0.25	0.6%	0.3%
NO_x Cost	$0.15	0.3%	$0.24	0.6%	0.4%
Other	$0.03	0.1%	$0.15	0.4%	0.3%
Municipal Waste	$0.02	0.0%	$0.01	0.0%	0.0%
Market-to-Market Adder	($0.01)	(0.0%)	$0.01	0.0%	0.0%
FMU Adder	$0.76	1.3%	$0.00	0.0%	(1.3%)
Emergency DR Adder	$2.40	4.1%	$0.00	0.0%	(4.1%)
Scarcity Adder	$0.13	0.2%	$0.00	0.0%	(0.2%)
Constraint Violation Adder	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Uranium	($0.01)	(0.0%)	($0.00)	(0.0%)	0.0%
Decrease Generation Adder	($0.19)	(0.3%)	($0.06)	(0.2%)	0.2%
Wind	($0.01)	(0.0%)	($0.07)	(0.2%)	(0.2%)
LPA-SCED Differential	($0.01)	(0.0%)	($0.11)	(0.3%)	(0.3%)
Total	$58.60	100.0%	$38.94	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 3-69 and

Table 3-73) markup is simply the difference between the price offer and the cost offer. In the second approach, (Table 3-70 and Table 3-74) the 10 percent markup is removed from the cost offers of coal units.

The components of LMP are shown in Table 3-70, including markup using adjusted cost offers.

Day-Ahead LMP

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

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-36 shows the hourly distribution of PJM day-ahead average LMP for the first nine months of 2014 and 2015.

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

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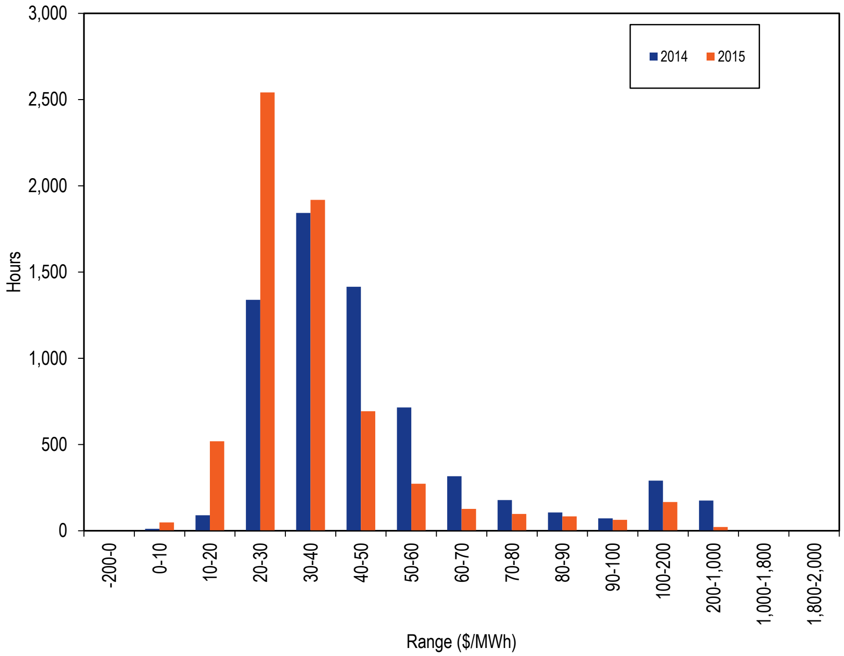
Figure 3-36 Average LMP for the PJM Day-Ahead Energy Market: January through September 2014 and 2015



PJM Day-Ahead, Average LMP

Table 3-71 shows the PJM day-ahead, average LMP for the first nine months of each year of the 15-year period 2001 to 2015.

Table 3-71 PJM day-ahead, average LMP (Dollars per MWh): January through September of 2001 through 2015

	Day-Ahead LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.07	$30.02	$34.25	NA	NA	NA
2002	$28.29	$22.54	$19.09	(21.6%)	(24.9%)	(44.3%)
2003	$41.20	$38.24	$22.02	45.6%	69.7%	15.4%
2004	$42.64	$42.07	$17.47	3.5%	10.0%	(20.7%)
2005	$54.48	$46.67	$28.83	27.8%	10.9%	65.1%
2006	$50.45	$46.32	$24.93	(7.4%)	(0.8%)	(13.5%)
2007	$54.24	$51.40	$24.95	7.5%	11.0%	0.1%
2008	$71.43	$66.38	$33.11	31.7%	29.2%	32.7%
2009	$37.35	$35.29	$14.32	(47.7%)	(46.8%)	(56.8%)
2010	$45.81	$41.03	$19.59	22.7%	16.3%	36.8%
2011	$45.14	$40.20	$22.68	(1.5%)	(2.0%)	15.7%
2012	$32.16	$30.10	$14.54	(28.8%)	(25.1%)	(35.9%)
2013	$37.50	$34.70	$16.96	16.6%	15.3%	16.6%
2014	$53.76	$39.92	$58.98	43.4%	15.0%	247.8%
2015	$36.67	$30.56	$25.21	(31.8%)	(23.4%)	(57.3%)

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 3-72 shows the PJM day-ahead, load-weighted, average LMP for the first nine months of each year of the 15-year period 2001 to 2015.

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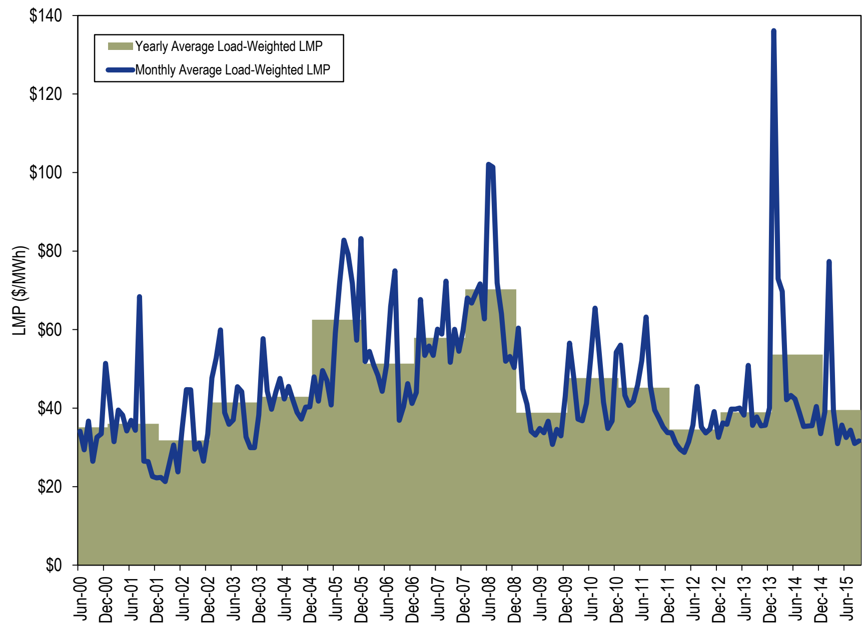
Table 3-72 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through September 2001 through 2015

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$39.88	$32.68	$42.01	NA	NA	NA
2002	$32.29	$25.22	$22.81	(19.0%)	(22.8%)	(45.7%)
2003	$44.11	$41.51	$22.34	36.6%	64.6%	(2.1%)
2004	$44.59	$44.47	$17.40	1.1%	7.1%	(22.1%)
2005	$59.51	$51.33	$31.13	33.5%	15.4%	78.9%
2006	$54.19	$48.87	$28.35	(8.9%)	(4.8%)	(8.9%)
2007	$57.79	$55.62	$26.07	6.6%	13.8%	(8.0%)
2008	$75.96	$70.35	$35.19	31.5%	26.5%	35.0%
2009	$39.35	$36.92	$14.98	(48.2%)	(47.5%)	(57.4%)
2010	$49.12	$43.33	$21.35	24.8%	17.4%	42.6%
2011	$48.34	$42.35	$26.54	(1.6%)	(2.3%)	24.3%
2012	$34.29	$31.17	$17.12	(29.1%)	(26.4%)	(35.5%)
2013	$39.49	$35.96	$19.90	15.1%	15.4%	16.3%
2014	$59.09	$42.08	$67.27	49.6%	17.0%	238.0%
2015	$39.51	$32.15	$28.05	(33.1%)	(23.6%)	(58.3%)

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

Figure 3-37 shows the PJM day-ahead, monthly and annual, load-weighted LMP from June 2000 through September 2015.[71]

Figure 3-37 Day-ahead, monthly and annual, load-weighted, average LMP: June 2000 through September 2015



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

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

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the Day-Ahead Energy Market with an offer price that cannot be decomposed. Using identified marginal resource offers and the components of unit offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_X, SO_2 and CO_2 emission credits, emission rates for NO_X, emission rates for SO_2 and emission rates for CO_2. CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware and Maryland.[72] Day-ahead scheduling reserve (DASR) lost opportunity cost (LOC) and DASR offer adders are the calculated contribution to LMP when redispatch of resources is needed in order to satisfy DASR requirements. The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal.

The components of day-ahead LMP are shown in Table 3-73 including markup using unadjusted cost offers. Table 3-73 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In the first nine months of 2015, 28.7 percent of the load-weighted LMP was the result of coal cost, 14.6 percent of the load-weighted LMP was the result of gas cost, 4.6 percent was the result of the up to congestion transaction cost, 22.3 percent was the result of DEC bid cost and 11.5 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.[73]

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

Table 3-73 Components of PJM day-ahead, (unadjusted) nine month, load-weighted, average LMP (Dollars per MWh): January through September of 2014 and 2015

	2014 (Jan - Sep)		2015 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$10.92	18.5%	$11.36	28.7%	10.3%
DEC	$9.33	15.8%	$8.82	22.3%	6.5%
Gas	$12.59	21.3%	$5.78	14.6%	(6.7%)
INC	$8.75	14.8%	$4.56	11.5%	(3.3%)
Ten Percent Cost Adder	$2.63	4.4%	$2.01	5.1%	0.7%
Up-to Congestion Transaction	$8.01	13.6%	$1.80	4.6%	(9.0%)
VOM	$1.48	2.5%	$1.48	3.7%	1.2%
Dispatchable Transaction	$2.84	4.8%	$1.24	3.1%	(1.7%)
Oil	$1.03	1.7%	$1.05	2.7%	0.9%
DASR LOC Adder	($0.04)	(0.1%)	$0.35	0.9%	1.0%
SO_2	$0.01	0.0%	$0.26	0.7%	0.6%
DASR Offer Adder	$0.06	0.1%	$0.22	0.5%	0.4%
Markup	($0.23)	(0.4%)	$0.17	0.4%	0.8%
NO_x	$0.09	0.2%	$0.13	0.3%	0.2%
CO_2	$0.14	0.2%	$0.10	0.3%	0.0%
Price Sensitive Demand	$1.09	1.8%	$0.06	0.1%	(1.7%)
Municipal Waste	$0.02	0.0%	$0.01	0.0%	(0.0%)
Other	$0.00	0.0%	$0.00	0.0%	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%	(0.0%)
Wind	($0.01)	(0.0%)	($0.03)	(0.1%)	(0.0%)
FMU Adder	$0.41	0.7%	$0.00	0.0%	(0.7%)
NA	($0.01)	(0.0%)	$0.14	0.4%	0.4%
Total	$59.09	100.0%	$39.51	100.0%	0.0%

Table 3-74 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.

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Table 3-74 Components of PJM day-ahead, (adjusted) nine month, load-weighted, average LMP (Dollars per MWh): January through September of 2014 and 2015

	2014 (Jan - Sep)		2015 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$10.89	18.4%	$11.36	28.7%	10.3%
DEC	$9.33	15.8%	$8.82	22.3%	6.5%
Gas	$12.59	21.3%	$5.78	14.6%	(6.7%)
INC	$8.75	14.8%	$4.56	11.5%	(3.3%)
Up-to Congestion Transaction	$8.01	13.6%	$1.80	4.6%	(9.0%)
VOM	$1.48	2.5%	$1.48	3.7%	1.2%
Ten Percent Cost Adder	$1.43	2.4%	$1.37	3.5%	1.1%
Dispatchable Transaction	$2.84	4.8%	$1.24	3.1%	(1.7%)
Oil	$1.03	1.7%	$1.05	2.7%	0.9%
Markup	$1.01	1.7%	$0.81	2.1%	0.3%
DASR LOC Adder	($0.04)	(0.1%)	$0.35	0.9%	1.0%
SO_2	$0.01	0.0%	$0.26	0.7%	0.6%
DASR Offer Adder	$0.06	0.1%	$0.22	0.5%	0.4%
NO_x	$0.09	0.2%	$0.13	0.3%	0.2%
CO_2	$0.14	0.2%	$0.10	0.3%	0.0%
Price Sensitive Demand	$1.09	1.8%	$0.06	0.1%	(1.7%)
Municipal Waste	$0.02	0.0%	$0.01	0.0%	(0.0%)
Other	$0.00	0.0%	$0.00	0.0%	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%	(0.0%)
Wind	($0.01)	(0.0%)	($0.03)	(0.1%)	(0.0%)
FMU Adder	$0.41	0.7%	$0.00	0.0%	(0.7%)
NA	($0.01)	(0.0%)	$0.15	0.4%	0.4%
Total	$59.09	100.0%	$39.51	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.

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

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

Table 3-75 shows the number of cleared UTC transactions, the number of profitable cleared UTCs, the number of cleared UTCs that were profitable at their source point and the number of cleared UTCs that were profitable at their sink point in the first nine months of 2014 and 2015. In the first nine months of 2015, 52.7 percent of all cleared UTC transactions were net profitable, with 65.8 percent of the source side profitable and 36.0 percent of the sink side profitable.

Table 3-75 Cleared UTC profitability by source and sink point: January through September 2014 and 2015[74]

(Jan-Sep)	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	Profitable UTC	Profitable Source	Profitable Sink
2014	18,446,114	10,209,549	12,451,325	6,198,169	55.3%	67.5%	33.6%
2015	6,428,413	3,388,207	4,227,618	2,312,002	52.7%	65.8%	36.0%

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

Substantial virtual trading activity does not guarantee that market power cannot be exercised in the Day-Ahead Energy Market. Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis (Figure 3-39).

Table 3-76 shows that the difference between the average real-time price and the average day-ahead price was -$1.04 per MWh in the first nine months of 2014, and -$0.70 per MWh in the first nine months of 2015. The difference between average peak real-time price and the average peak day-ahead price was -$1.72 per MWh in the first nine months of 2014 and -$2.16 per MWh in the first nine months of 2015.

74 Calculations exclude PJM administrative charges.

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Table 3-76 Day-ahead and real-time average LMP (Dollars per MWh): January through September, 2014 and 2015[75]

	2014 (Jan-Sep)				2015 (Jan-Sep)			
	Day Ahead	Real Time	Difference	Percent of Real Time	Day Ahead	Real Time	Difference	Percent of Real Time
Average	$53.76	$52.72	($1.04)	(2.0%)	$36.67	$35.96	($0.70)	(2.0%)
Median	$39.92	$36.06	($3.86)	(10.7%)	$30.56	$27.88	($2.69)	(9.6%)
Standard deviation	$58.98	$74.17	$15.18	20.5%	$25.21	$30.75	$5.54	18.0%
Peak average	$67.11	$65.39	($1.72)	(2.6%)	$43.93	$41.77	($2.16)	(5.2%)
Peak median	$47.70	$42.97	($4.73)	(11.0%)	$35.59	$31.90	($3.69)	(11.6%)
Peak standard deviation	$73.24	$93.17	$19.94	21.4%	$29.02	$31.71	$2.69	8.5%
Off peak average	$42.09	$41.64	($0.45)	(1.1%)	$30.32	$30.89	$0.57	1.8%
Off peak median	$32.85	$30.34	($2.52)	(8.3%)	$25.59	$24.73	($0.86)	(3.5%)
Off peak standard deviation	$39.24	$49.58	$10.34	20.9%	$19.21	$28.95	$9.74	33.7%

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

Table 3-77 shows the difference between the real-time and the day-ahead energy market prices for January through September in each year of the 15-year period 2001 to 2015.

Table 3-77 Day-ahead and real-time average LMP (Dollars per MWh): January through September 2001 through 2015

(Jan-Sep)	Day Ahead	Real Time	Difference	Percent of Real Time
2001	$36.07	$36.00	($0.07)	(0.2%)
2002	$28.29	$28.13	($0.16)	(0.6%)
2003	$41.20	$40.42	($0.77)	(1.9%)
2004	$42.64	$43.85	$1.22	2.9%
2005	$54.48	$54.69	$0.21	0.4%
2006	$50.45	$51.79	$1.34	2.7%
2007	$54.24	$57.34	$3.10	5.7%
2008	$71.43	$71.94	$0.51	0.7%
2009	$37.35	$37.42	$0.08	0.2%
2010	$45.81	$46.13	$0.32	0.7%
2011	$45.14	$45.79	$0.65	1.4%
2012	$32.16	$32.45	$0.29	0.9%
2013	$37.50	$37.30	($0.20)	(0.5%)
2014	$53.76	$52.72	($1.04)	(1.9%)
2015	$36.67	$35.96	($0.70)	(1.9%)

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

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Table 3-78 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for January through September of 2007 through 2015.

Table 3-78 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): January through September of 2007 through 2015

(Jan-Sep)	2007		2008		2009		2010		2011		2012		2013		2014		2015	
LMP	Freq	Cumulative Percent	Freq	Cumulative Percent	Freq	Cumulative Percent	Freq	Cumulative Percent	Freq	Cumulative Percent	Freq	Cumulative Percent	Freq	Cumulative Percent	Freq	Cumulative Percent	Freq	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($1,000) to ($750)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	2	0.03%	0	0.00%
($750) to ($500)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	3	0.08%	0	0.00%
($500) to ($450)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.09%	0	0.00%
($450) to ($400)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	6	0.18%	0	0.00%
($400) to ($350)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	5	0.26%	0	0.00%
($350) to ($300)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	5	0.34%	0	0.00%
($300) to ($250)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	6	0.43%	0	0.00%
($250) to ($200)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%	1	0.02%	14	0.64%	1	0.02%
($200) to ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%	4	0.08%	3	0.06%	14	0.85%	4	0.08%
($150) to ($100)	0	0.00%	1	0.02%	0	0.00%	0	0.00%	2	0.05%	6	0.17%	5	0.14%	45	1.54%	17	0.34%
($100) to ($50)	26	0.40%	88	1.35%	3	0.05%	13	0.20%	49	0.79%	17	0.43%	9	0.27%	89	2.90%	65	1.33%
($50) to $0	3,385	52.07%	3,730	58.08%	3,776	57.69%	4,091	62.65%	4,011	62.02%	4,112	62.97%	4,338	66.49%	4,301	68.55%	4,417	68.75%
$0 to $50	2,914	96.55%	2,448	95.32%	2,736	99.45%	2,288	97.57%	2,290	96.98%	2,343	98.60%	2,112	98.73%	1,871	97.11%	1,901	97.77%
$50 to $100	193	99.50%	264	99.33%	34	99.97%	130	99.56%	169	99.56%	61	99.53%	58	99.62%	97	98.60%	101	99.31%
$100 to $150	21	99.82%	37	99.89%	2	100.00%	20	99.86%	21	99.88%	14	99.74%	12	99.80%	37	99.16%	33	99.82%
$150 to $200	4	99.88%	4	99.95%	0	100.00%	8	99.98%	2	99.91%	10	99.89%	10	99.95%	18	99.44%	7	99.92%
$200 to $250	1	99.89%	2	99.98%	0	100.00%	1	100.00%	3	99.95%	4	99.95%	1	99.97%	9	99.57%	3	99.97%
$250 to $300	3	99.94%	0	99.98%	0	100.00%	0	100.00%	0	99.95%	1	99.97%	2	100.00%	8	99.69%	1	99.98%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.95%	2	100.00%	0	100.00%	3	99.74%	1	100.00%
$350 to $400	0	99.97%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%	0	100.00%	3	99.79%	0	100.00%
$400 to $450	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%	0	100.00%	2	99.82%	0	100.00%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%	0	100.00%	0	99.82%	0	100.00%
$500 to $750	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%	0	100.00%	7	99.92%	0	100.00%
$750 to $1,000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.92%	0	100.00%
$1,000 to $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	99.94%	0	100.00%
>= $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	4	100.00%	0	100.00%

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Figure 3-38 shows the hourly differences between day-ahead and real-time hourly LMP in the first nine months of 2015.

Figure 3-38 Real-time hourly LMP minus day-ahead hourly LMP: January through September 2015

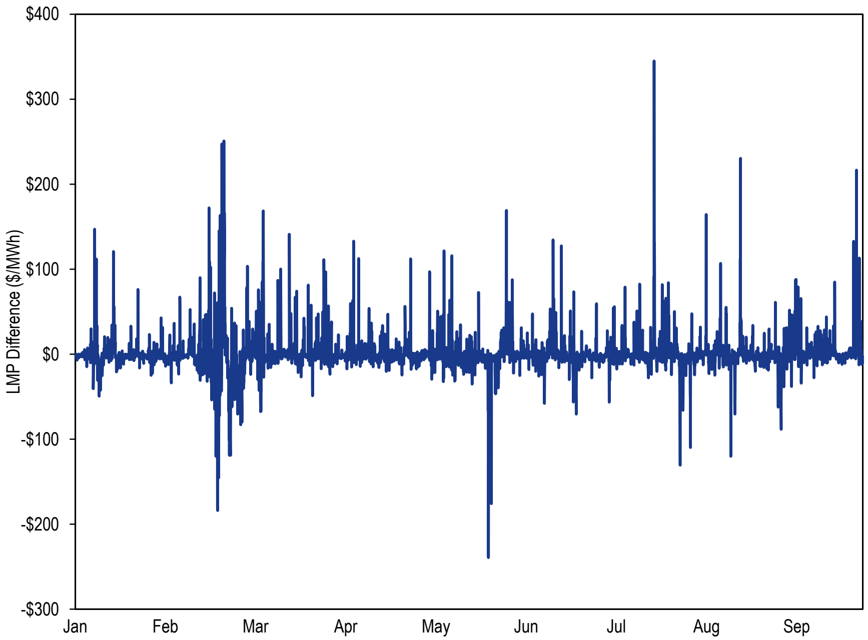

Figure 3-39 shows the monthly average differences between the day-ahead and real-time LMP in the first nine months of 2015.

Figure 3-39 Monthly average of real-time minus day-ahead LMP: January 2014 through September 2015

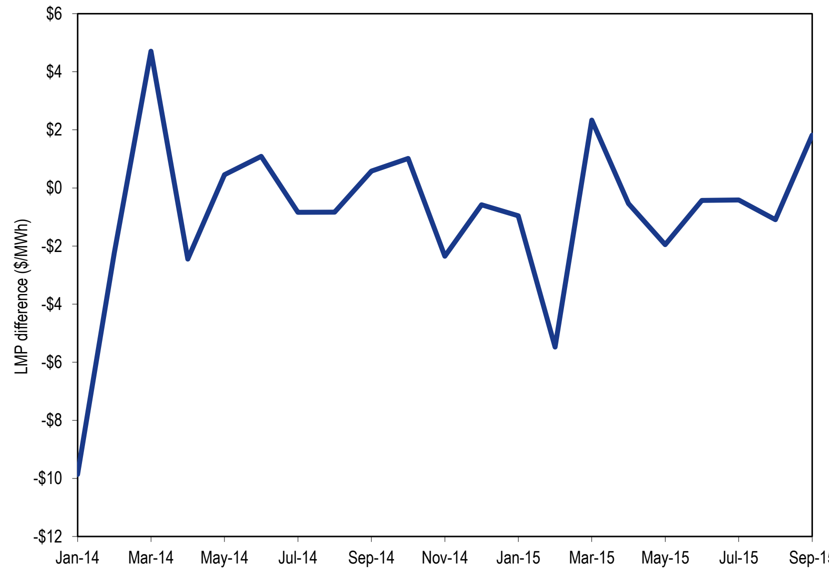

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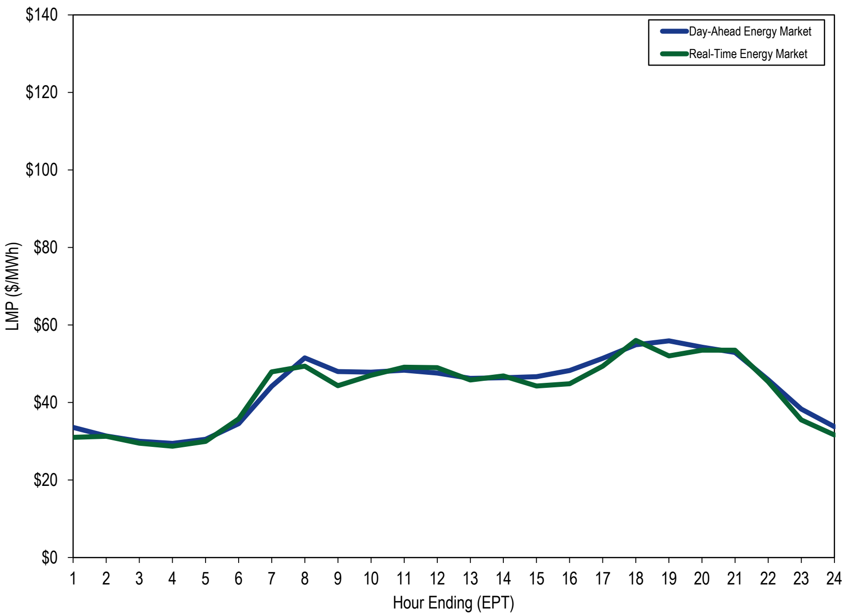
Figure 3-40 shows day-ahead and real-time LMP on an average hourly basis for the first nine months of 2015.

Figure 3-40 PJM system hourly average LMP: January through September 2015



Scarcity

PJM's Energy Market experienced no shortage pricing events in the first nine months of 2015 compared to two days in the first nine months of 2014. Table 3-79 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in the first nine months of 2014 and 2015.

Table 3-79 Summary of emergency events declared: January through September, 2014 and 2015

	Number of days events declared	
Event Type	Jan - Sep, 2014	Jan - Sep, 2015
Cold Weather Alert	25	26
Hot Weather Alert	7	19
Maximum Emergency Generation Alert	6	1
Primary Reserve Alert	2	0
Voltage Reduction Alert	2	0
Primary Reserve Warning	1	0
Voltage Reduction Warning	4	0
Pre Emergency Mandatory Load Management Reduction Action	0	2
Emergency Load Management Long Lead Time	6	2
Emergency Load Management Short Lead Time	6	2
Maximum Emergency Action	8	1
Emergency Energy Bids Requested	3	0
Voltage Reduction Action	1	0
Shortage Pricing	2	0
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 26 days in the first nine months of 2015 compared to 25 days in the first nine months of 2014.[76] The purpose of a cold weather alert is to prepare personnel and facilities for expected extreme cold

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

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weather conditions, generally when temperatures are forecast to approach minimums or fall below ten degrees Fahrenheit.

PJM declared hot weather alerts on 19 days in the first nine months of 2015 compared to seven days in the first nine months of 2014.[77] 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 a maximum emergency generation alert on one day in the first nine months of 2015 compared to six days in the first nine months of 2014. The alert was issued for a sub-zone of the Dominion Zone for local transmission, and was cancelled less than an hour after it was declared. 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.[78] 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 did not declare any primary reserve alert in the first nine months of 2015 compared to two days in the first nine months of 2014. The purpose of a primary reserve alert is to alert members at least one day prior to the operating day that available primary reserves are anticipated to be short of the primary reserve requirement on the operating day. It is issued when the estimated primary reserves are less than the forecast primary reserve requirement.

PJM did not declare any voltage reduction alert in the first nine months of 2015, compared to two days the first nine months of 2014. The purpose of a voltage reduction alert is to alert members at least one day prior to the operating day that a voltage reduction may be required on the operating day. It is issued when the estimated operating reserve is less than the forecast synchronized reserve requirement.

77 See PJM. "Manual 13: Emergency Operations," Revision 57 (January 1, 2015), Section 3.4 Hot Weather Alert, p. 50.
78 See PJM. "Manual 13: Emergency Operations," Revision 57 (January 1, 2015), Section 2.3.1 Advance Notice Emergency Procedures: Alerts, p. 16.

PJM did not declare any primary reserve warning in the first nine months of 2015, compared to one day in the first nine months of 2014. The purpose of a primary reserve warning is to warn members that available primary reserves are less than the primary reserve requirement but greater than the synchronized reserve requirement.

PJM did not declare any voltage reduction warning and reduction of non-critical plant load in the first nine months of 2015 compared to four days in the first nine months of 2014. The purpose of a voltage reduction warning and reduction of non-critical plant load is to warn members that available synchronized reserves are less than the synchronized reserve requirement and that a voltage reduction may be required. It can be issued for the RTO or for specific control zones.

PJM declared emergency mandatory load management reductions on two days in the first nine months of 2015 compared to six days in all or parts of the PJM service territory in the first nine months of 2014. The purpose of emergency mandatory load management is to request curtailment service providers (CSP) to implement load reductions from demand resources registered in PJM demand response programs that have a lead time of between one and two hours (long lead time) and a lead time of up to one hour (short lead time). Starting in June 2014, PJM combined the long lead and short lead emergency load management action procedures into Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time). PJM dispatch declares NERC Energy Emergency Alert level 2 (EEA2) concurrent with Emergency Mandatory load Management Reductions. PJM also added a Pre-Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time) step to request load reductions before declaring emergency load management reductions. PJM declared Pre-Emergency Mandatory Load Management Reduction Action on two days in the first nine months of 2015.

PJM declared maximum emergency generation action on one day in the first nine months of 2015 compared to eight days in the first nine months of 2014. The purpose of a maximum emergency generation action is to request generators to increase output to the maximum emergency level which unit

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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.

PJM did not request any bids for emergency energy purchases in the first nine months of 2015 compared to three days in the first nine months of 2014.

PJM did not declare any voltage reduction actions in the first three months of 2015 compared to one day (January 6) in the first nine months of 2014. The purpose of a voltage reduction is to reduce load to provide sufficient reserves, to maintain tie flow schedules, and to preserve limited energy sources. When a voltage reduction action is issued for a reserve zone or sub-zone, the primary reserve penalty factor and synchronized reserve penalty factor are incorporated into the synchronized and non-synchronized reserve market clearing prices and locational marginal prices until the voltage reduction action has been terminated.

There were 17 synchronized reserve events in the first nine months of 2015 compared to 29 in the first nine months of 2014.[79] 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 3-80 provides a description of PJM declared emergency procedures.

Table 3-80 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 that 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 requirement and that voltage reduction may be required.
Pre-Emergency Mandatory Load Management Reduction Action (30, 60 or 120-minute)	To request any site registered in the PJM demand response program as a demand resource (DR) that needs 30, 60 or 120 minute lead time to provide load relief. This is declared prior to or with out PJM dispatch issuing a NERC Energy Emergency Alert Level 2 (EEA2).
Emergency Mandatory Load Management Reduction Action (30, 60 or 120-minute)	To request any site registered in the PJM demand response program as a demand resource (DR) that needs 30, 60 or 120 minute lead time to provide load relief. A NERC EEA2 is declared concurrent with the issuance of Emergency Mandatory Load Management Reductions.
Maximum Emergency 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 Action	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.

79 See *2015 Quarterly State of the Market Report for PJM: January through September*, Section 10: Ancillary Service Markets for details on the spinning events.

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Table 3-81 shows when emergency alerts and warnings were declared and when emergency actions were implemented in the first nine months of 2015.

Table 3-81 PJM declared emergency alerts, warnings and actions: January through September, 2015

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	Pre-Emergency Mandatory Load Management Reduction	Maximum Emergency Generation Action	Emergency Mandatory Load Management Reduction	Voltage Reduction	Manual Load Dump Warning	Load Shed Directive
1/5/2015	ComEd												
1/6/2015	ComEd												
1/7/2015	PJM Western Region												
1/8/2015	PJM												
1/9/2015	PJM Western Region												
1/10/2015	PJM Western Region												
1/14/2015	PJM Western Region												
1/15/2015	PJM Western Region												
2/2/2015	PJM												
2/3/2015	PJM												
2/5/2015	ComEd,DLCO,ATSI												
2/6/2015	Mid-Atlantic												
2/13/2015	DLCO,AP,ATSI												
2/14/2015	PJM Western Region												
2/15/2015	Mid-Atlantic,PJM Western Region												
2/16/2015	PJM												
2/17/2015	Mid-Atlantic												
2/18/2015	PJM Western Region												
2/19/2015	PJM												
2/20/2015	PJM												
2/21/2015												AEP	
2/23/2015	PJM Western Region												
2/24/2015	PJM												
2/26/2015	DLCO,ATSI												
2/27/2015	PJM Western Region												
3/5/2015	ComEd												
3/6/2015	PJM Western Region												
4/21/2015								Penelec	Penelec	Penelec			
4/22/2015								Penelec		Penelec			
5/26/2015		Mid-Atlantic,PJM Southern Region											
5/27/2015		Mid-Atlantic,PJM Southern Region											AEP (Milton, WV)
6/11/2015		Mid-Atlantic,PJM Southern Region											
6/12/2015		Mid-Atlantic,PJM Southern Region											
6/13/2015		Mid-Atlantic,PJM Southern Region											
6/16/2015		PJM Southern Region											
6/21/2015		PJM Southern Region											
6/22/2015		Mid-Atlantic,PJM Southern Region											
6/23/2015		Mid-Atlantic,PJM Southern Region											AECO
7/20/2015		Mid-Atlantic, Dominion											
7/21/2015		Mid-Atlantic											
7/29/2015		Mid-Atlantic, Dominion	Dominion (Sub-zone)										
7/30/2015		Mid-Atlantic, Dominion											
8/17/2015		Mid-Atlantic											
9/1/2015		Mid-Atlantic											
9/2/2015		Mid-Atlantic											
9/3/2015		Mid-Atlantic											
9/8/2015		Mid-Atlantic											
9/9/2015		Mid-Atlantic											

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Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, including 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.[80] 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 nine months of 2015, there were no shortage pricing events triggered in PJM compared to two days in the first nine months of 2014.

NOPR on Shortage Pricing

On September 17, 2015, the Commission issued a Notice of Proposed Rulemaking (NOPR) in which the Commission proposed to address price formation issues in RTOs/ISOs ("price formation NOPR").[81] In particular, the price formation NOPR proposes (i) to require the alignment of settlement and dispatch intervals for energy and operating reserves; and (ii) to require that each RTO/ISO trigger shortage pricing for any dispatch interval during which a shortage of energy or operating reserves occurs. These proposed reforms are intended to ensure that resources have price signals that provide incentives to conform their output to dispatch instructions, and that prices reflect operating needs at each dispatch interval.[82]

Currently in PJM, if the dispatch tools reflect shortage of reserves (primary or synchronized) for a time period shorter than a defined threshold (30 minutes in practice) due to ramp limitations or unit startup delays, it is considered a 'transient shortage,' a shortage event is not declared, and shortage pricing is not implemented. The rationale for having a minimum threshold time for a reserve shortage is to reflect the fact that the level of reserve measurement accuracy does not support a shorter time period. The rationale for including voltage reduction actions and manual load dump actions as triggers for shortage pricing is to reflect the fact that when dispatchers need to take these emergency actions to maintain reliability, the system is short reserves and prices should reflect that condition, even if the data does not show a shortage of reserves.[83]

If PJM were to move to a shortage pricing mechanism that is triggered by transient shortages, there needs to be accurate measurement of real time reserves that can support such a definition. That does not appear to be the case at present in PJM.

PJM Cold Weather Operations 2015

Natural gas supply and prices

As of January 1, 2015, gas fired generation was 30.7 percent (56,364.5 MW) of the total installed PJM capacity (183,726MW).[84] 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.

During the first three months of 2014 and 2015, a number of interstate gas pipelines that supply fuel for generators in the PJM service territory issued restriction notices limiting the availability of non-firm transportation services.

80 See PJM OATT, 2.2 (d) General, (February 25, 2014), pp. 1815, 1819.
81 152 FERC ¶ 61,218 (September 17, 2015).
82 *Id* at P 5.
83 *See*, e.g., Scarcity and Shortage Pricing, Offer Mitigation and Offer Caps Workshop, Docket No. AD14-14-000, Transcript 29:21- 30:14 (Oct. 28, 2014)
84 *2015 Quarterly State of the Market Report for PJM: January through September*, Section 5: Capacity Market, at Installed Capacity.

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These notices include warnings of operational flow orders (OFO) and actual OFOs. OFOs may 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 nominated quantities. Pipelines may also enforce strict balancing constraints which limit the ability of gas users (without no notice service or storage service) to deviate from the 24 hour ratable take and which limit the ability of users to have access to unused gas.

Pipeline operators use restrictive and inflexible rules to manage the balance of supply and demand during extreme operating conditions. The independent operations of geographically overlapping pipelines during extreme conditions highlights the potential shortcomings of a gas pipeline network that relies on individual pipelines to manage the balancing of supply and demand. The independent operational restrictions imposed by pipelines and the impact on electric generators during extreme conditions suggests there may be potential benefits to creating an ISO/RTO structure to coordinate the supply of gas across pipelines and with the electric RTOs, or the creation of a gas supply coordination framework under existing electric ISO/RTOs.

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.[85] 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.

During the extreme cold weather conditions in the first three months of 2015, a number of gas fired generators requested temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters that were affected because of gas pipeline restrictions include minimum run time (MRT) and turn down ratio (TDR, ratio of economic maximum MW to economic minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may be forced to nominate an equal amount of gas for each hour in a 24 hour period, with penalties for deviating from the nominated quantity. This led to requests for 24 hour minimum run times and turn down ratios close to 1, to avoid deviations from the hourly nominated quantity.

Key parameters like startup and notification time were not limited by the PLS matrix through the first nine months of 2015. Some resource owners notified PJM that they needed extended notification times based on the claimed necessity for generation owners to nominate gas prior to gas nomination cycle deadlines.

Parameter Limited Schedules under Capacity Performance

Beginning in delivery year 2016-2017, resources that have Capacity Performance (CP) commitments are required to submit, in their parameter limited schedules (cost based offers and price based PLS offers), unit specific parameters that reflect the physical capability of the technology type of the resource. In its order on Capacity Performance ("June 9th Order"), the Commission determined that resources should be able to reflect actual constraints based on not just the resource physical constraints, but also other constraints, such as contractual limits that are not based on the physical characteristics of the generator.[86] The Commission found that it is unjust and unreasonable to not provide uplift payments to resources with parameters based on non-physical constraints.[87] The Commission directed PJM to submit tariff language to establish a process through which resources that operate outside the defined unit-specific parameter limits can justify such operation and therefore remain eligible for make-whole payments.[88]

A primary goal of the Capacity Performance market design is to assign performance risk to generation owners and to ensure that capacity prices reflect underlying supply and demand conditions, including the cost of taking on performance risk. The Order's determination on parameters is not consistent with that goal. By permitting generation owners to establish unit

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

86 *PJM Interconnection, L.L.C. et al.,* 151 FERC ¶ 61,208 at P 437.
87 *Id* at P 439.
88 *Id* at P 440.

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parameters based on non-physical limits, the June 9th Order has weakened the incentives for units to be flexible and has weakened the assignment of performance risk to generation owners. Contractual limits, unlike generating unit operational limits, are a function of the interests and incentives of the parties to the contracts. If a generation owner expects to be compensated through uplift payments for running for 24 hours regardless of whether the energy is economic or needed, that generation owner has no incentive to pay more to purchase the flexible gas service that would permit the unit to be flexible in response to dispatch.

The fact that a contract may be just and reasonable because it was an arm's length contract entered into by two willing parties does not mean that is the only possible arrangement between the two parties or that it is consistent with an efficient market outcome. The actual contractual terms are a function of the incentives and interests of the parties. The fact that a just and reasonable contract exists between a generation owner and a gas supplier does not mean that it is appropriate or efficient to impose the resultant costs on electric customers or that it incorporates an efficient allocation of performance risk between the generation owner and other market participants.

The approach to parameters defined in the June 9th Order would increase energy market uplift payments substantially. Uplift costs are unpredictable, opaque and unhedgeable. Electric customers are not in a position to determine the terms of the contracts that resources enter into. Customers rely on the market rules to create incentives that protect them by assigning operational risk to generators, who are in the best position to efficiently manage those risks.

The Market Monitor suggests that the revised rules recognize the difference between operational parameters that indicate to PJM dispatchers what a unit is capable of during the operating day and the parameters that are reflected in uplift payments. The parameters provided to PJM dispatchers each day should reflect what units are physically capable of. That is an operational necessity. However, the parameters which determine the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct. These parameters can be either the OEM parameters associated with new units or they can reflect defined flexibility goals. Paying energy market uplift on the basis of parameters consistent with the flexibility goals of the capacity performance construct would ensure that performance incentives are consistent across the capacity and energy markets and ensure that performance risk is appropriately assigned to generation owners.

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