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 in the first nine months of 2017, 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 2017.

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 but the aggregate market power test based on pivotal suppliers indicates that the aggregate day-ahead market structure was not competitive on every day. The hourly HHI (Herfindahl-Hirschman Index) results indicate that by FERC standards, the PJM energy market in the first nine months of 2017 was unconcentrated. Average HHI was 929 with a minimum of 696 and a maximum of 1208 in the first nine months of 2017. The fact that the average HHI is in the unconcentrated range and the maximum hourly HHI is in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. As demonstrated for the day-ahead market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power. The PJM energy market peaking segment of supply was highly concentrated.
- 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 identified local market power and resulted in offer capping to force competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed because unit owners can exercise market power even when mitigated.
- 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 both routinely and during periods of high demand is consistent with 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.

1 Analysis of 2017 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 *2015 State of the Market Report for PJM*, Appendix A, "PJM Geography."

- Market design was evaluated as effective because the analysis shows that the PJM energy market resulted in competitive market outcomes. In general, 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 identifies market power and causes the market to provide competitive market outcomes in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. The role of UTCs in the Day-Ahead Energy Market continues to cause concerns.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[2] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM energy market, this occurs primarily 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, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of variable operating and maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Now that generators will be allowed to modify offers hourly, market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the new rules permitting cost-based offers in excess of $1,000 per MWh.

2 OATT Attachment M (PJM Market Monitoring Plan).

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.

Overview

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. The maximum of average offered real-time generation increased by 2,551 MW, or 1.5 percent, from 171,300 MW in the summer of 2016 to 173,851 MW in the summer of 2017. In the first nine months of 2017, 3,941.0 MW of new resources were added, 2,072.8 MW were retired.

  PJM average real-time cleared generation in the first nine months of 2017 decreased by 1,141 MW, or 1.2 percent, from the first nine months of 2016, from 92,799 MW to 91,658 MW.

  PJM average day-ahead cleared supply in the first nine months of 2017, including INCs and up to congestion transactions, increased by 0.2 percent from the first nine months of 2016, from 133,089 MW to 133,377 MW.

- **Aggregate Pivotal Suppliers.** The PJM energy market at times requires generation from pivotal suppliers to meet the daily peak load, resulting in aggregate market power even when the HHI level indicates that the aggregate market is unconcentrated. Based on the HHI, the PJM energy market was unconcentrated overall with low concentration in the baseload segment, moderate concentration in the intermediate segment, and high concentration in the peaking segment.

- **Generation Fuel Mix.** In the first nine months of 2017, coal units provided 32.2 percent, nuclear units 35.3 percent and natural gas units 26.8 percent of total generation. Compared to the first nine months of 2016, generation from coal units decreased 6.2 percent, generations from natural gas units decreased 2.8 percent and generation from nuclear units increased 2.5 percent.

- **Fuel Diversity.** In the first nine months of 2017, the fuel diversity of energy generation, measured by the fuel diversity index for energy (FDI_e), increased 0.7 percent over the first nine months of 2016.
- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first nine months of 2017, coal units were 32.5 percent of marginal resources and natural gas units were 52.9 percent of marginal resources. In the first nine months of 2016, coal units were 46.2 percent and natural gas units were 41.4 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market, in the first nine months of 2017, up to congestion transactions were 80.4 percent of marginal resources, INCs were 5.5 percent of marginal resources, DECs were 10.1 percent of marginal resources, and generation resources were 4.0 percent of marginal resources. In the first nine months of 2016, up to congestion transactions were 81.9 percent of marginal resources, INCs were 4.3 percent of marginal resources, DECs were 8.9 percent of marginal resources, and generation resources were 4.9 percent of marginal resources.
- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM accounting peak load during the first nine months of 2017 was 145,636 MW in the HE 1700 on July 19, 2017, which was 6,541 MW, 4.3 percent, lower than the PJM peak load for the first nine months of 2016, which was 152,177 MW in the HE 1500 on August 11, 2016.

  PJM average real-time load in the first nine months of 2017 decreased by 3.7 percent from 2016, from 90,599 MW to 87,243 MW. PJM average day-ahead demand in the first nine months of 2017, including DECs and up to congestion transactions, decreased by 0.5 percent in the first nine months of 2016, from 129,070 MW to 128,450 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 2017, 15.5 percent of real-time load was supplied by bilateral contracts, 28.5 percent by spot market purchases and 56.0 percent by self-supply. Compared with the first nine months of 2016, reliance on bilateral contracts increased by 2.6 percentage points, reliance on spot market purchases increased by 4.6 percentage points and reliance on self-supply decreased by 7.2 percentage points.
- **Supply and Demand: Scarcity.** Five minute shortage pricing was triggered on one day in the first nine months of 2017.

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 when the rules are designed and implemented properly. 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 decreased from 0.1 percent in the first nine months of 2016 to 0 percent in the first nine months of 2017. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 0.4 percent in the first nine months of 2016 to 0.3 percent in the first nine months of 2017.

  In the first nine months of 2017, eleven 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 identify 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. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.
- **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 percent in the first nine months of 2016 to 0.1 percent in the first nine months of

2017. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0 percent in the first nine months of 2016 to 0.1 percent in the first nine months of 2017.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the first nine months of 2017, in the PJM Real-Time Energy Market, 93.0 percent of marginal units had offer prices less than $50 per MWh. The average dollar markup of units with offer prices less than $25 was positive when using unadjusted cost offers. The average dollar markup of units with offer prices between $25 and $50 was positive when using unadjusted cost offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, demonstrating a revealed short run marginal cost that is less than the allowable cost-based offer under the PJM market rules. Some marginal units did have substantial markups. Using the unadjusted cost offers, the highest markup for any marginal unit in the first nine months of 2017 was $755.09 while the highest markup in the first nine months of 2016 was $258.16.

  In the first nine months of 2017, in the PJM Day-Ahead Energy Market, 94.3 percent of marginal generating units had offer prices less than $50 per MWh. The average dollar markup of units with offer prices less than $25 was positive when using unadjusted cost offers. The average dollar markup of units with offer prices between $25 and $50 was positive when using unadjusted cost offers. Using the unadjusted cost offers, the highest markup for any marginal units in the first nine months of 2017 was $47.74, while the highest markup in the first nine months of 2016 was $170.99.

- **Markup.** The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

  The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power.

- **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 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 since December 2014.

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. In the first nine months of 2017, the average hourly increment offers submitted MW increased by 21.4 percent from 7,017 MW in the first nine months of 2016 to 8,521 MW in the first nine months of 2017, and cleared MW increased by 6.5 percent from 4,577 MW in the first nine months of 2016 to 4,876 MW in the first nine months of 2017. In the first nine months of 2017, the average hourly decrement bids submitted MW increased by 20.7 percent from 6,918 MW in the first nine months of 2016 to 8,349 MW in the first nine months of 2017, and cleared MW increased by 7.6 percent from 4,087 MW in the first nine months of 2016 to 4,397 MW in the first nine months of 2017. In the first nine months of 2017, the average hourly up to congestion submitted MW increased by 1.1 percent from 143,885 MW in the first nine months of 2016 to 145,467 MW in the first nine months of 2017, and cleared MW increased by 6.6 percent from 34,204 MW in the first nine months of 2016 to 36,478 MW in the first nine months of 2017.

- **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. 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 2017, 55.3 percent were offered as available for economic dispatch, 3.7 percent were offered as emergency dispatch, 20.0 percent were offered as self scheduled, and 20.9 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 changes in supply and demand, generation fuel mix, the cost of fuel, emissions related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of closed loop interfaces related to demand side resources or reactive power, the application of transmission penalty factors, or the application of price setting logic.

  PJM real-time energy market prices increased in the first nine months of 2017 compared to the first nine months of 2016. The load-weighted average real-time LMP was 3.5 percent higher in the first nine months of 2017 than in first nine months of 2016, \$30.36 per MWh versus \$29.32 per MWh.

  PJM day-ahead energy market prices increased in the first nine months of 2017 compared to the first nine months of 2016. The load-weighted, average day-ahead LMP was 1.9 percent higher in the first nine months of 2017 than in the first nine months of 2016, \$30.26 per MWh versus \$29.69 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, in the first nine months of 2017, 30.4 percent of the load-weighted LMP was the result of coal costs, 38.3 percent was the result of gas costs and 2.12 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market, in the first nine months of 2017, 21.2 percent of the load-weighted LMP was the result of the coal costs, 23.1 percent was the result of the DEC bid costs, 18.2 percent was the result of the gas costs, 23.2 percent was the result of the INC bid costs, and 3.0 percent was the result of the up to congestion transaction costs.

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

  In the PJM Real-Time Energy Market in the first nine months of 2017, the adjusted markup component of LMP was \$4.74 per MWh or 15.6 percent of the PJM real-time, load-weighted, average LMP. May had the highest adjusted peak markup component, \$8.23 per MWh, or 21.72 percent of the real-time, peak hour load-weighted, average LMP. Using the unadjusted cost offers, the highest markup of a marginal unit in the first nine months of 2017 was \$755.09 per MWh. There were 37 hours in the first nine months of 2017 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded \$45.82 per MWh.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In the first nine months of 2017, the adjusted markup component of LMP resulting from generation resources was \$1.97 per MWh or 6.5 percent of the PJM day-ahead load-weighted average LMP. September had the highest adjusted markup component, \$2.98 per MWh or 9.4 percent of the day-ahead load-weighted average LMP. Using the unadjusted cost offers, the highest markup of a marginal unit in the first nine months of 2017 was \$47.74 per MWh.

  Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the Day-Ahead and Real-Time Energy Markets, although the behavior of some participants is consistent with economic withholding.

- **Price Convergence.** Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. The difference between the average day-ahead and real-time prices was -\$0.11 per MWh in the first nine months of 2016 and -\$0.47 per MWh in the first nine months of

2017. 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

- PJM implemented five minute shortage pricing beginning May 11, 2017. Five minute shortage pricing was triggered for the first time on September 21, 2017. The shortage pricing was triggered for 21 intervals between 1400 and 1700 on that day.

Recommendations

- The MMU recommends that the market rules should explicitly require that offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate. (Priority: Medium. First reported 2009. Status: Not adopted.)
- 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 2015. Status: Not adopted.)
- The MMU recommends that PJM require that the level of incremental costs includable in cost offers not exceed the unit's short run marginal cost. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that Manual 15 be replaced with a straightforward description of the components of cost offers based on short run marginal costs and the correct calculation of cost offers. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revisions to the calculation of energy market opportunity costs to incorporate all time based offer parameters and all limitations that impact the opportunity cost of generating unit output. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constant across the full MWh range of price and cost offers, that there be at least one

cost-based offer using the same fuel as the available price-based offer. (Priority: High. First reported 2015. Status: Not adopted.)

- The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available non-PLS price-based offer, and that the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that capacity performance resources and base capacity resources (during the June through September period) be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that under the capacity performance construct, PJM 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 used for capacity performance assessment as well as uplift payments. The parameters which determine nonperformance charges and the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the dispatcher to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. The LMPs in excess of $1,800 per MWh on January 7, 2014, were potentially a result of the way in which PJM modeled zonal (not nodal) demand response as a marginal resource. (Priority: Low. First reported 2014. Status: Not Adopted.)
- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. First reported 2015. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[4] (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM 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.[5] There is currently no PJM documentation in the tariff or manuals explaining

4 OATT § 1 (Definitions – OATT Definitions - L-M-N) (June 1, 2017) at 76.
5 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.

how hubs are created and how their definitions are changed.[6] (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 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 remove nonspecific 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. (Priority: Medium. First reported 2015. Status: Partially 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: Partially 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: Partially adopted.)
- The MMU recommends that PJM continue to enhance its posting of market data to promote market efficiency. (Priority: Medium. First reported 2005. Status: Partially adopted.)
- The MMU recommends the elimination of FMU and AU adders. 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: Partially adopted, 2014.)
- 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 2014. Status: Adopted in full, 2014.)

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first nine months of 2017, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

PJM average real-time cleared generation decreased by 1,141 MW, 1.2 percent, and peak load decreased by 6,541 MW, 4.3 percent, in the first nine months of 2017 compared to the first nine months of 2016. The relationship between supply and demand, regardless of the specific market, balanced by market concentration and the extent of pivotal suppliers, is referred to as the 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 although aggregate market power does exist for a significant number of hours. Market concentration levels remained in the unconcentrated range on average although there is high concentration in the peaking segment of the supply curve which adds to concerns about market power when market conditions are tight. Low average aggregate concentration does not mean that market power cannot be exercised. It is possible that market power can be exercised at times when individual suppliers or small groups of suppliers are pivotal even when the HHI level does not indicate that the market is highly concentrated. High markups for some units demonstrate the potential to exercise market power during high demand conditions. As demonstrated for the day-ahead market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.

6 The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

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 2017 generally reflected supply-demand fundamentals, although the behavior of some participants during high demand periods is consistent with economic withholding. Economic withholding is the ability to increase markups substantially in tight market conditions. There are additional issues in the energy market including the uncertainties about the pricing and availability of natural gas, the way that generation owners incorporate natural gas costs in offers, and 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.[7] 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 require offer capping of owners when the local market structure is noncompetitive.

However, there are some issues with the application of market power mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test. There is no tariff or manual language that defines in detail the application of the TPS test and offer capping in the Day-Ahead Energy Market and the Real-Time 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 resolved by simple rule changes requiring 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, that the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer, and requiring cost-based and price-based PLS offers to be at least as flexible as price-based non-PLS offers.

Another issue with the application of market power mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test is related to the definition of a competitive offer. A competitive offer is equal to short run marginal costs. The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, as interpreted by PJM, is not currently correct. Some unit owners include costs that are not short run marginal costs in offers, including maintenance costs. This issue can be resolved by simple changes to the PJM market rules to incorporate a clear and accurate definition of short run marginal costs.

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

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

in the energy market. These units are committed manually in both the Day-Ahead and Real-Time 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 based on measured reserve levels and transparent 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 net 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. PJM implemented five minute scarcity pricing on May 11, 2017, and implemented two step operating reserve demand curves on July 12, 2017. There are also significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on measured reserve levels (the current triggers are based on estimated reserves) and the lack of adequate locational scarcity pricing options.

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 in 2014, 2015 or 2016. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods is consistent with economic withholding. Given the structure of the energy market which can permit the exercise of aggregate market power at times of high demand, the tighter market conditions 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 2017.

Market Structure

Market Concentration

Analysis of supply curve segments of the PJM energy market in the first nine months of 2017 indicates low concentration in the base load segment and moderate concentration in the intermediate segment, but high concentration in the peaking segment.[8] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal in the aggregate market during high demand periods. The fact that the average HHI is in the unconcentrated range and the maximum hourly HHI is in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. It is possible to have pivotal suppliers in the aggregate market even when the HHI level does not indicate highly concentrated. It is possible to have an exercise of market power even when the HHI level does not indicate highly concentrated.

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 the first nine months of 2017, although there are issues with the application of market power mitigation for resources whose owners fail the TPS test that permit local market power to be exercised even when mitigation rules are applied. These issues include the lack of a method for consistently determining the

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

cheaper of the cost and price schedules, and the lack of rules requiring that cost based offers equal to short run marginal costs.

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).

The HHI may not accurately capture market power issues in situations where, for example, there is moderate concentration in all on line resources but there is a high level of concentration in resources needed to meet increases in load. The HHIs for supply curve segments is an indication of such issues with the ownership of incremental resources. An aggregate pivotal supplier test is required to accurately measure the ability of incremental resources to exercise market power when load is high, for example.

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 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.[9]

9 See "*Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement*, 77 FERC ¶ 61,263 *mimeo* at 80 (1996).

PJM HHI Results

Calculations for hourly HHI indicate that by FERC standards, the PJM energy market during the first nine months of 2017 was unconcentrated (Table 3-2).

Table 3-2 PJM hourly energy market HHI: January 1 through September 30, 2016 and 2017[10]

	Hourly Market HHI (Jan - Sep, 2016)	Hourly Market HHI (Jan - Sep, 2017)
Average	1023	929
Minimum	786	696
Maximum	1356	1208
Highest market share (One hour)	28%	27%
Average of the highest hourly market share	20%	18%
# Hours	6,575	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 2016 and 2017. The PJM energy market was moderately concentrated overall with low concentration in the baseload, moderate concentration in the intermediate segment, and high concentration in the peaking segment.

Table 3-3 PJM hourly energy market HHI (By supply segment): January 1 through September 30, 2016 and 2017

	Jan - Sep, 2016			Jan - Sep, 2017		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	974	1117	1443	831	982	1254
Intermediate	533	1700	8102	779	1740	9894
Peak	647	6052	10000	705	5967	10000

Figure 3-1 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in the first nine months of 2017.

10 This analysis includes all hours in the first nine months of 2016 and 2017, regardless of congestion.

Figure 3-1 Fuel source distribution in unit segments: January 1 through September 30, 2017[11]

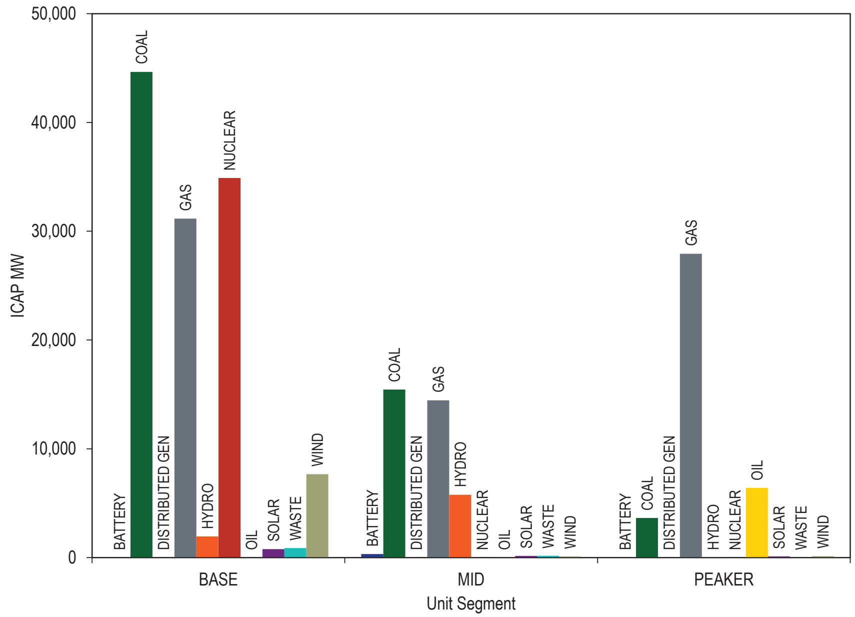
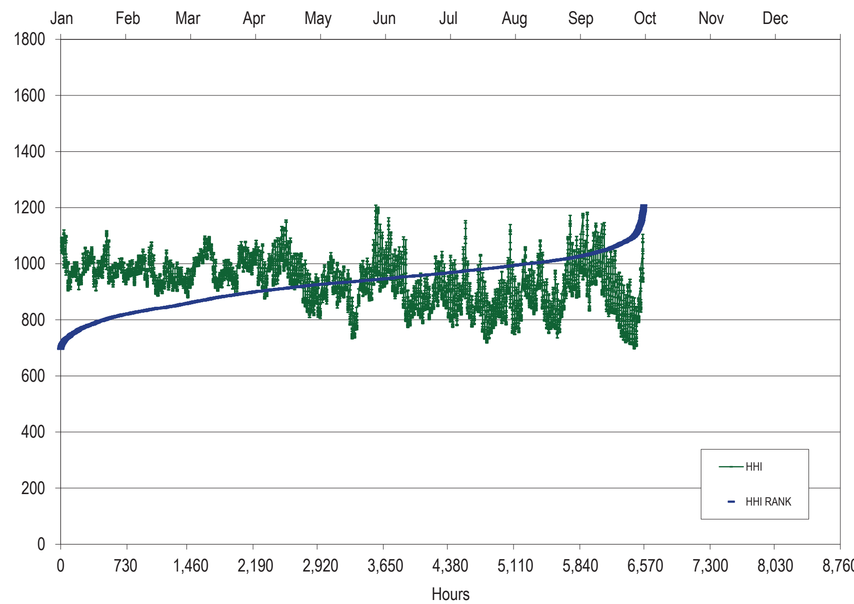


Figure 3-2 presents the hourly HHI values in chronological order and an HHI duration curve for the first nine months of 2017.

Figure 3-2 PJM hourly energy market HHI: January 1 through September 30, 2017



Aggregate Market Pivotal Supplier Results

Notwithstanding the HHI level, a supplier may have the incentive and ability to raise energy market prices. If reliably meeting the PJM system load requires energy from a single supplier, that supplier is pivotal and has monopoly power in the aggregate energy market. If a small number of suppliers are jointly required to meet load, those suppliers are jointly pivotal and have oligopoly power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.

11 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. See PJM. "Net Energy Metering Senior Task Force (NEMSTF) Action on Proposed Manual 28 Rev.," (July 26, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20120726/20120726-item-04-nemstf-report-and-proposed-manual-revisions.ashx>.

In the PJM Day-Ahead Energy Market, two suppliers were jointly pivotal on 20 percent of days in the first nine months of 2017. Three suppliers were jointly pivotal on 73 percent of days. The frequency of pivotal suppliers increased in the summer months and on high demand days in September.

Day-Ahead Energy Market Aggregate Pivotal Suppliers

To assess the number of pivotal suppliers in the Day-Ahead Energy Market, the MMU determined, for each supplier, the MW available for economic commitment that were already running or were available to start between the close of the Day-Ahead Energy Market and the peak load hour of the operating day. The available supply is defined as MW offered at a price less than 150 percent of the applicable LMP because supply available at higher prices is not competing to meet the demand for energy.[12] Generating units, import transactions, economic demand response, and INCs, are included for each supplier. Demand is the total MW required by PJM to meet physical load, cleared load bids, export transactions, and DECs. A supplier is pivotal if PJM would require some portion of the supplier's available economic capacity in the peak hour of the operating day in order to meet demand. Suppliers are jointly pivotal if PJM would require some portion of the joint suppliers' available economic capacity in the peak hour of the operating day in order to meet demand.

Figure 3-3 shows the number of days in the first nine months of 2017 with one pivotal supplier, two jointly pivotal suppliers, and three jointly pivotal suppliers for the Day-Ahead Energy Market along with the number of suppliers meeting each criterion. No supplier was singly pivotal for any day in the first nine months of 2017. Two suppliers were jointly pivotal on 52 days, while HHI levels did not exceed 702. When there were two jointly pivotal suppliers, one specific supplier was jointly pivotal with one to ten other suppliers, as shown in Figure 3-3. Three suppliers were jointly pivotal on 161 days, despite persistently unconcentrated average HHI levels.

12 Each LMP is scaled by 150 percent to determine the relevant supply, resulting in a different price threshold for each LMP value. The analysis does not solve a redispatch of the PJM market.

Figure 3-3 Days with pivotal suppliers and numbers of pivotal suppliers in the PJM Day-Ahead Energy Market: January through September, 2017

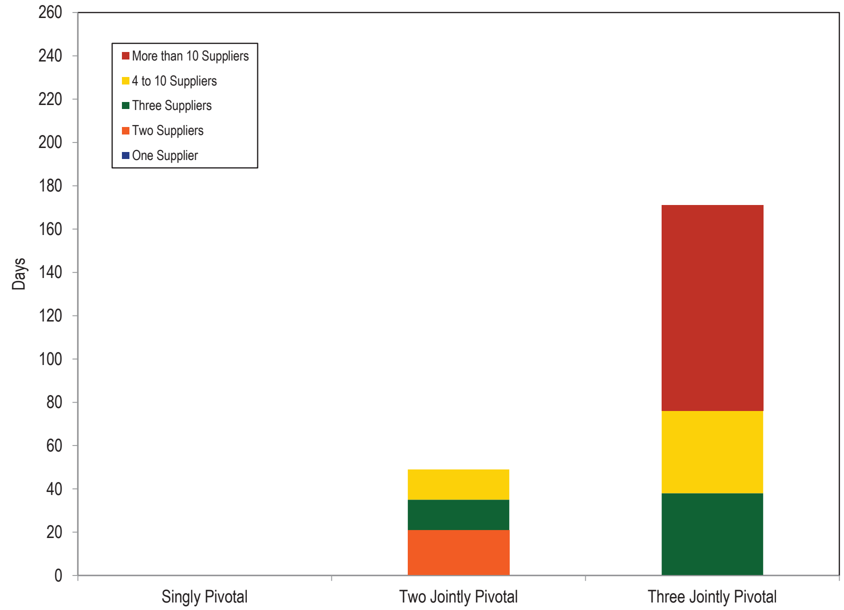


Table 3-4 provides the frequency with which each of the ten largest suppliers was singly or jointly pivotal for the Day-Ahead Energy Market in the first nine months of 2017. The two largest suppliers were pivotal on 52 and 51 days, 19 percent of days in the first nine months of 2017. All of the top 10 suppliers were one of three pivotal suppliers on at least 32 percent of days, and the largest two suppliers were one of three pivotal suppliers on 73 percent of days.

Table 3-4 Frequency of days as a pivotal supplier for the 10 largest suppliers: January 1 through September 30, 2017

Pivotal Supplier Rank	Days Singly Pivotal	Percent of Days	Days Jointly Pivotal with One Other Supplier	Percent of Days	Days Jointly Pivotal with Two Other Suppliers	Percent of Days
1	0	0%	52	19%	199	73%
2	0	0%	51	19%	198	73%
3	0	0%	29	11%	185	68%
4	0	0%	17	6%	161	59%
5	0	0%	10	4%	147	54%
6	0	0%	5	2%	112	41%
7	0	0%	2	1%	127	47%
8	0	0%	2	1%	114	42%
9	0	0%	1	0%	103	38%
10	0	0%	1	0%	87	32%

The current market power mitigation rules for the PJM energy market rely on the assumption that the aggregate market includes sufficient competing sellers to ensure competitive market outcomes. With sufficient competition, any attempt to economically or physically withhold generation would not result in higher market prices, because another supplier would replace the generation at a similar price. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not correct, as demonstrated by these results. There are pivotal suppliers in the aggregate energy market.

The existing market power mitigation measures do not address aggregate market power.[13] The MMU is developing an aggregate market power test for the day-ahead and real-time energy markets based on pivotal suppliers and will propose appropriate market power mitigation rules to address aggregate market power.

Ownership of Marginal Resources

Table 3-5 shows the contribution to real-time, load-weighted LMP by individual marginal resource owner.[14] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of 2017, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. In the first nine months of 2017, the offers of one company resulted in 13.8 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies resulted in 50.0 percent of the real-time, load-weighted, average PJM system LMP. During the first nine months of 2016, the offers of one company resulted in 24.2 percent of the real-time, load-weighted PJM system LMP and offers of the top four companies resulted in 61.2 percent of the real-time, load-weighted, average PJM system LMP. In the first nine months of 2017, the offers of one company resulted in 13.2 percent of the peak hour real-time, load weighted PJM system LMP. In the first nine months of 2016, the offers of one company resulted in 24.4 percent of the peak hour, real-time, load weighted PJM system LMP.

13 One supplier, Exelon, is partially mitigated for aggregate market power through its merger agreement. The agreement is not part of the PJM market rules. See Monitoring Analytics, LLC, Letter attaching Settlement Terms and Conditions, FERC Docket No. EC11-83-000 and Maryland PSC Case No. 9271 (October 11, 2011).

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

Table 3-5 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): January 1 through September 30, 2016 and 2017

2016 (Jan-Sep)						2017 (Jan - Sep)					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	24.2%	24.2%	1	24.4%	24.4%	1	13.8%	13.8%	1	13.2%	13.2%
2	14.8%	39.0%	2	15.4%	39.8%	2	13.6%	27.4%	2	12.6%	25.7%
3	12.9%	51.9%	3	10.9%	50.7%	3	12.1%	39.5%	3	10.9%	36.6%
4	9.3%	61.2%	4	9.5%	60.2%	4	10.5%	50.0%	4	10.0%	46.7%
5	8.1%	69.3%	5	7.0%	67.2%	5	9.8%	59.8%	5	9.1%	55.8%
6	5.4%	74.8%	6	4.9%	72.1%	6	4.4%	64.2%	6	5.8%	61.6%
7	2.2%	77.0%	7	3.0%	75.1%	7	3.8%	68.0%	7	5.1%	66.7%
8	2.1%	79.1%	8	2.5%	77.6%	8	3.5%	71.5%	8	3.5%	70.3%
9	2.0%	81.1%	9	2.5%	80.1%	9	3.5%	75.0%	9	3.3%	73.6%
Other (68 companies)	18.9%	100.0%	Other (60 companies)	19.9%	100.0%	Other (73 companies)	25.0%	100.0%	Other (67 companies)	26.4%	100.0%

Table 3-6 Marginal resource contribution to PJM day-ahead, load-weighted LMP (By parent company): January 1 through September 30, 2016 and 2017

2016 (Jan - Sep)						2017 (Jan - Sep)					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	14.4%	14.4%	1	12.8%	12.8%	1	9.6%	9.6%	1	12.0%	12.0%
2	9.2%	23.6%	2	12.0%	12.0%	2	8.1%	17.7%	2	6.9%	18.9%
3	7.4%	31.0%	3	9.1%	9.1%	3	6.7%	24.4%	3	5.3%	24.1%
4	7.0%	38.0%	4	8.9%	8.9%	4	6.0%	30.4%	4	5.1%	29.3%
5	6.8%	44.8%	5	6.5%	6.5%	5	5.5%	35.9%	5	4.9%	34.2%
6	5.5%	50.3%	6	6.5%	6.5%	6	5.3%	41.2%	6	4.7%	38.9%
7	4.5%	54.8%	7	5.2%	5.2%	7	4.9%	46.1%	7	4.6%	43.5%
8	4.3%	59.2%	8	3.5%	3.5%	8	4.4%	50.5%	8	4.5%	48.1%
9	3.2%	62.4%	9	3.2%	3.2%	9	3.8%	54.4%	9	4.3%	52.4%
Other (164 companies)	37.6%	100.0%	Other (157 companies)	32.2%	32.2%	Other (152 companies)	45.6%	100.0%	Other (147 companies)	47.6%	100.0%

Table 3-6 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[15] The contribution of each marginal resource to price at each load bus is calculated hourly, and summed by the parent company that offers the marginal resource into the Day-Ahead Energy Market. The results show that in the first nine months of 2017, the offers of one company contributed 9.6 percent of the day-ahead, load-weighted, PJM system LMP and that the offers of the top four companies contributed 30.4 percent of the day-ahead, load-weighted, average PJM system LMP. In the first nine months of 2016, the offers of one company contributed 14.4 percent of the day-ahead, load-weighted PJM system LMP and offers of the top four companies contributed 38.0 percent of the day-ahead, load-weighted, average PJM system LMP.

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 3-7 shows the type of fuel used by marginal resources in the Real-Time Energy Market. There can be more than one marginal resource in

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

any given interval as a result of transmission constraints. In the first nine months of 2017, coal units were 32.5 percent and natural gas units were 52.9 percent of marginal resources. In the first nine months of 2016, coal units were 46.2 percent and natural gas units were 41.4 percent of the total marginal resources. In the first nine months of 2017, 74.1 percent of the wind marginal units had negative offer prices, 18.9 percent had zero offer prices and 6.9 percent had positive offer prices.

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.[16]

The proportion of marginal nuclear units increased from 0.03 percent in the first nine months of 2015 to 0.92 percent in the first nine months of 2016 and to 1.25 percent in the first nine months of 2017. The increase was primarily due to a small number of nuclear units offering with a dispatchable range. Most nuclear units are offered as fixed generation in the PJM market. The dispatchable nuclear units do not always respond to dispatch instructions.

Table 3-7 Type of fuel used (By real-time marginal units): January 1 through September 30, 2013 through 2017

	Jan-Sep				
Type/Fuel	2013	2014	2015	2016	2017
Gas	34.13%	42.48%	34.88%	41.41%	52.92%
Coal	57.56%	49.71%	54.46%	46.21%	32.53%
Wind	4.75%	3.86%	2.74%	2.67%	8.44%
Oil	3.22%	3.44%	7.39%	8.55%	4.45%
Uranium	0.02%	0.06%	0.03%	0.92%	1.25%
Other	0.21%	0.35%	0.43%	0.15%	0.32%
Municipal Waste	0.08%	0.04%	0.06%	0.10%	0.08%
Emergency DR	0.03%	0.05%	0.00%	0.00%	0.00%

16 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.

Figure 3-4 shows the type of fuel used by marginal resources in the Real-Time Energy Market since 2004. The role of coal as a marginal resource has declined while the role of gas as a marginal resource has increased.

Figure 3-4 Type of fuel used (By real-time marginal units): January 1 through September 30, 2004 through 2017

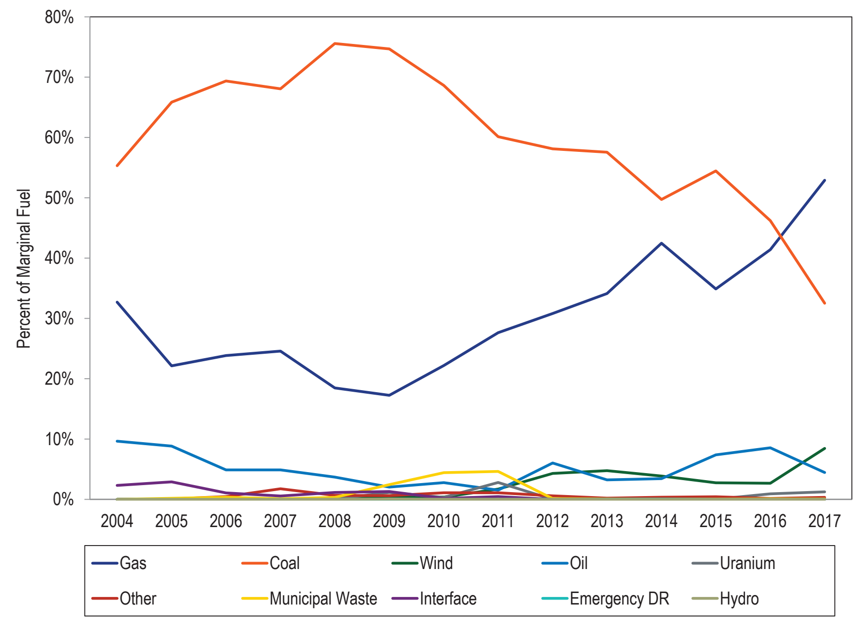


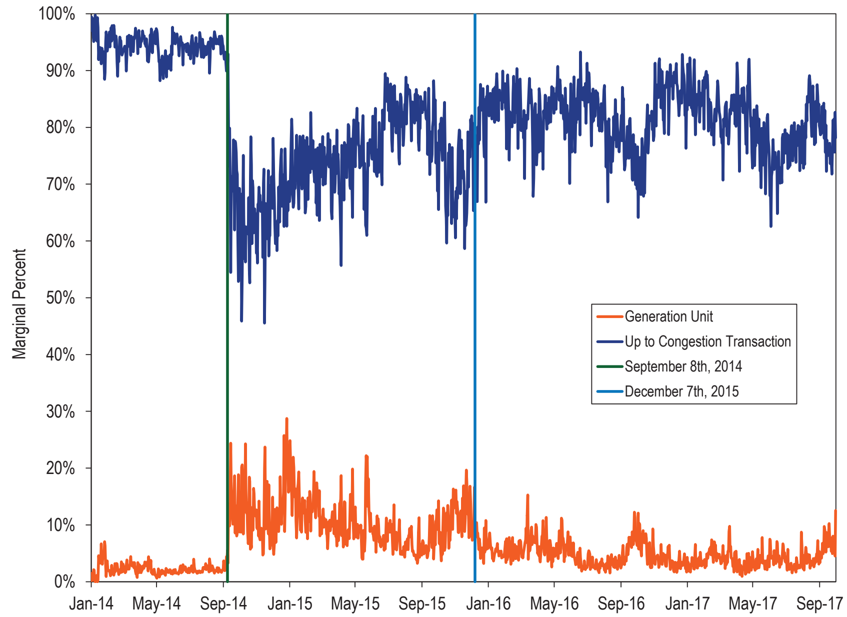
Table 3-8 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first nine months of 2017, up to congestion transactions were 80.37 percent of marginal resources. Up to congestion transactions were 81.88 percent of marginal resources in the first nine months of 2016.

Table 3-8 Day-ahead marginal resources by type/fuel: January 1 through September 30, 2011 through 2017

	(Jan - Sep)						
Type/Fuel	2011	2012	2013	2014	2015	2016	2017
Up to Congestion Transaction	69.42%	86.73%	96.23%	93.69%	76.47%	81.88%	80.37%
DEC	14.40%	5.15%	1.24%	2.19%	8.58%	8.89%	10.09%
INC	8.44%	4.36%	1.01%	1.59%	4.94%	4.25%	5.53%
Coal	5.36%	2.46%	0.97%	1.44%	6.08%	2.24%	1.71%
Gas	1.78%	1.12%	0.44%	0.95%	3.20%	2.02%	1.83%
Oil	0.00%	0.00%	0.00%	0.02%	0.21%	0.52%	0.19%
Uranium	0.00%	0.00%	0.00%	0.00%	0.00%	0.10%	0.06%
Dispatchable Transaction	0.24%	0.07%	0.06%	0.08%	0.31%	0.05%	0.03%
Wind	0.07%	0.04%	0.04%	0.03%	0.14%	0.04%	0.17%
Other	0.00%	0.00%	0.00%	0.00%	0.02%	0.01%	0.00%
Price Sensitive Demand	0.28%	0.05%	0.01%	0.01%	0.03%	0.00%	0.00%
Municipal Waste	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%
Water	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Figure 3-5 shows, for the Day-Ahead Energy Market from January 1, 2014, through September 30, 2017, the daily proportion of marginal resources that were up to congestion transaction and/or generation units. The percent of marginal up to congestion transactions decreased significantly and that of generation units increased beginning on September 8, 2014, as a result of FERC's UTC uplift refund notice which became effective on that date.[17] That trend has reversed as a result of the expiration of the fifteen month uplift refund period for UTC transactions.

Figure 3-5 Day-ahead marginal up to congestion transaction and generation units: January 1, 2014 through September 30, 2017



17 See 18 CFR § 385.213 (2014).

Supply

Supply includes physical generation and imports and virtual transactions.

Figure 3-6 shows the average PJM aggregate real-time generation supply curves by offer price for the entire range of offers, peak load and average load for the summer of 2016 and 2017. The maximum of average offered real-time generation increased by 2,551 MW, or 1.5 percent, from 171,300 MW in the summer of 2016 to 173,851 MW in the summer of 2017.

Figure 3-6 Average PJM aggregate real-time generation supply curves by offer price: summer of 2016 and 2017

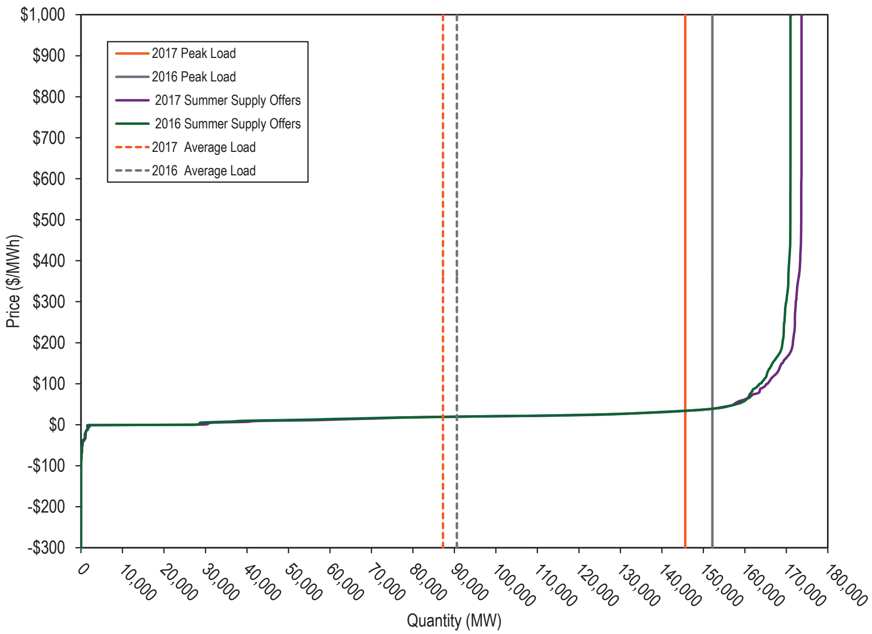
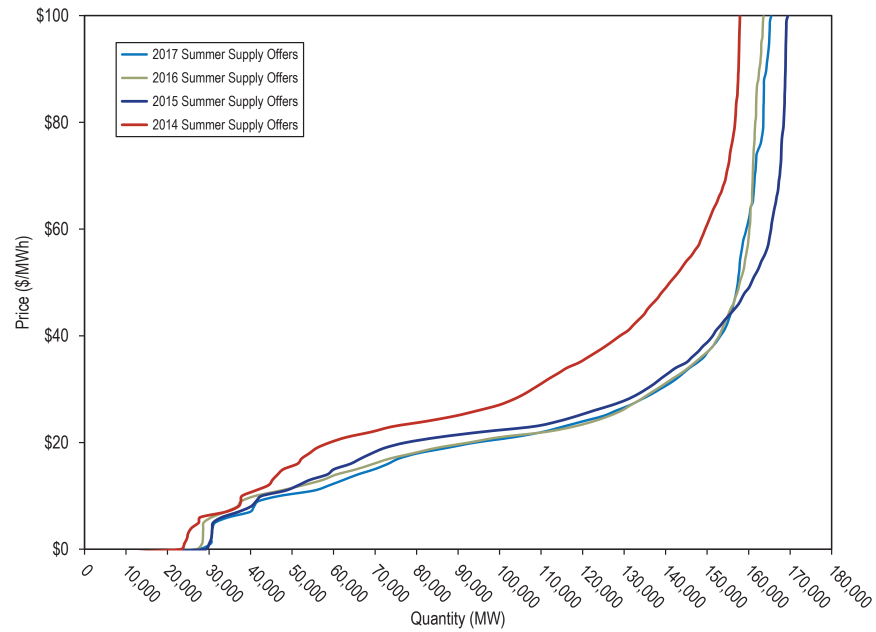


Figure 3-7 shows the average PJM aggregate real-time generation supply curves by offer price, for the typical dispatch range and for the summer of 2014 through 2017. Figure 3-7 shows that the supply curve is not flat in the typical dispatch range and that the supply curve has not become flatter over this period.

Figure 3-7 Average PJM aggregate real-time generation supply curves by offer price: summer of 2014 through 2017



Energy Production by Fuel Source

Table 3-9 shows PJM generation by fuel source in GWh for the first nine months of 2016 and 2017. In the first nine months of 2017, generation from coal units decreased 6.2 percent and generation from natural gas units increased 2.8 percent compared to the first nine months of 2016.[18]

Table 3-9 PJM generation (By fuel source (GWh)): January 1 through September 30, 2016 and 2017[19 20]

Jan - Sep		2016		2017		Change in
		GWh	Percent	GWh	Percent	Output
Coal		209,032.7	33.8%	195,979.8	32.2%	(6.24%)
	Bituminous	183,859.0	29.7%	169,203.3	27.8%	(7.97%)
	Sub Bituminous	21,119.7	3.4%	20,884.1	3.4%	(1.12%)
	Other Coal	4,054.0	0.7%	5,892.4	1.0%	45.35%
Nuclear		209,893.3	33.9%	215,089.3	35.3%	2.48%
Gas		169,493.9	27.4%	165,018.5	27.1%	(2.64%)
	Natural Gas	167,890.0	27.1%	163,207.1	26.8%	(2.79%)
	Landfill Gas	1,603.6	0.3%	1,797.0	0.3%	12.06%
	Other Gas	0.3	0.0%	14.3	0.0%	4,100.00%
Hydroelectric		10,930.0	1.8%	11,929.1	2.0%	9.14%
	Pumped Storage	3,862.2	0.6%	3,989.2	0.7%	3.29%
	Run of River	5,782.2	0.9%	6,633.4	1.1%	14.72%
	Other Hydro	1,285.6	0.2%	1,306.5	0.2%	1.62%
Wind		11,963.2	1.9%	14,268.3	2.3%	19.27%
Waste		3,089.0	0.5%	2,764.2	0.5%	(10.51%)
	Solid Waste	3,089.0	0.5%	2,764.2	0.5%	(10.51%)
	Miscellaneous	0.0	0.0%	0.0	0.0%	NA
Oil		1,752.6	0.3%	1,667.7	0.3%	(4.85%)
	Heavy Oil	256.1	0.0%	154.5	0.0%	(39.65%)
	Light Oil	298.3	0.0%	195.7	0.0%	(34.39%)
	Diesel	50.1	0.0%	24.8	0.0%	(50.59%)
	Gasoline	0.0	0.0%	0.0	0.0%	NA
	Kerosene	68.4	0.0%	1.2	0.0%	(98.28%)
	Jet Oil	0.0	0.0%	0.0	0.0%	NA
	Other Oil	1,079.7	0.2%	1,291.5	0.2%	19.62%
Solar, Net Energy Metering		799.2	0.1%	1,156.6	0.2%	44.71%
Energy Storage		12.0	0.0%	20.5	0.0%	70.75%
	Battery	12.0	0.0%	20.5	0.0%	70.75%
	Compressed Air	0.0	0.0%	0.0	0.0%	NA
Biofuel		1,414.3	0.2%	1,342.7	0.2%	(5.07%)
Geothermal		0.0	0.0%	0.0	0.0%	NA
Other Fuel Type		0.0	0.0%	48.2	0.0%	NA
Total		618,380.2	100.0%	609,284.8	100.0%	(1.5%)

18 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.
19 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.
20 Net Energy Metering is combined with Solar due to data confidentiality reasons.

Table 3-10 Monthly PJM generation (By fuel source (GWh)): January 1 through September 30, 2017

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Coal		25,111.3	19,246.2	21,910.6	17,843.2	19,836.7	22,512.3	26,748.3	23,892.6	18,878.6	195,979.8
	Bituminous	21,142.1	16,596.5	18,996.6	15,674.8	17,627.2	19,757.0	22,750.8	20,480.3	16,178.0	169,203.3
	Sub Bituminous	3,189.9	1,945.5	2,192.2	1,733.6	1,697.4	2,177.7	3,264.8	2,652.3	2,030.7	20,884.1
	Other Coal	779.3	704.2	721.8	434.9	512.1	577.6	732.7	760.0	669.9	5,892.4
Nuclear		26,016.6	22,140.8	23,047.7	23,076.4	22,564.3	24,441.8	25,419.2	25,180.0	23,202.6	215,089.3
Gas		16,071.3	15,213.3	17,834.3	13,438.8	15,290.3	20,016.6	24,184.6	22,139.1	20,830.3	165,018.5
	Natural Gas	15,884.4	15,017.6	17,625.2	13,234.8	15,096.3	19,822.6	23,975.8	21,923.2	20,627.3	163,207.1
	Landfill Gas	186.9	195.7	208.6	201.2	193.9	192.6	208.3	212.4	197.5	1,797.0
	Other Gas	0.0	0.1	0.6	2.8	0.1	1.4	0.5	3.4	5.5	14.3
Hydroelectric		1,266.9	1,083.6	1,215.3	1,432.4	1,620.7	1,552.8	1,536.4	1,305.7	915.3	11,929.1
	Pumped Storage	337.1	253.0	308.4	320.8	431.6	542.8	656.1	637.7	501.6	3,989.2
	Run of River	826.8	753.2	809.9	1,008.9	1,034.7	817.5	638.8	468.1	275.5	6,633.4
	Other Hydro	103.0	77.4	97.0	102.6	154.4	192.5	241.5	199.9	138.2	1,306.5
Wind		2,017.5	2,178.6	2,299.9	2,072.0	1,825.5	1,457.9	811.9	693.5	911.5	14,268.3
Waste		364.9	281.5	302.3	264.4	303.6	301.5	320.9	318.8	306.4	2,764.2
	Solid Waste	364.9	281.5	302.3	264.4	303.6	301.5	320.9	318.8	306.4	2,764.2
	Miscellaneous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil		210.9	152.6	112.9	142.8	214.7	226.0	200.4	201.3	206.1	1,667.7
	Heavy Oil	0.5	3.1	0.0	0.0	34.7	58.2	25.9	28.9	3.2	154.5
	Light Oil	59.7	21.8	5.8	4.9	21.6	19.8	11.4	8.1	42.5	195.7
	Diesel	6.0	0.1	1.1	1.2	5.6	2.6	1.9	2.3	4.0	24.8
	Gasoline	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Kerosene	0.8	0.0	0.1	0.0	0.0	0.0	0.2	0.1	0.0	1.2
	Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Other Oil	144.0	127.6	105.9	136.6	152.9	145.3	161.0	161.8	156.4	1,291.5
Solar, Net Energy Metering		52.6	93.1	121.0	134.8	141.2	161.2	160.1	150.9	141.5	1,156.6
Energy Storage		2.6	3.2	3.4	2.6	2.3	1.8	1.7	1.5	1.4	20.5
	Battery	2.6	3.2	3.4	2.6	2.3	1.8	1.7	1.5	1.4	20.5
	Compressed Air	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biofuel		152.7	158.3	175.8	141.6	109.7	167.3	174.8	181.8	80.9	1,342.7
Geothermal		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fuel Type		48.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	48.2
Total		71,315.5	60,551.1	67,023.0	58,549.0	61,908.9	70,839.1	79,558.4	74,065.1	65,474.7	609,284.8

Generator Offers

Generator offers are categorized as dispatchable (Table 3-11) or self scheduled (Table 3-12).[21] 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 3-11 and Table 3-12 do not include units that did not indicate their offer status and units that were offered as available to run only during emergency events. Units that do not indicate their offer status are unavailable for dispatch by PJM. The MW offered beyond the economic range of a unit are categorized as emergency MW. Emergency MW are included in both tables.

Table 3-11 shows the proportion of MW offers by dispatchable units, by unit type and by offer price range, in the first nine months of 2017. For example, 79.8 percent of CC offers were dispatchable and in the $0 to $200 per MWh offer price range. The total column is the proportion of all MW offers by unit type that were dispatchable. For example, 86.0 percent of all CC MW offers were dispatchable, including the 5.7 percent of emergency MW offered by CC units. The all dispatchable offers row is the proportion of MW that were offered as available for economic dispatch within a given range by all unit types. For example, 51.1 percent of all dispatchable offers were in the $0 to $200 per MWh price range. The total column in the all dispatchable offers row is the proportion of all MW offers that were offered as available for economic dispatch, including emergency MW. Among all the generator offers in the first nine months of 2017, 55.3 percent were offered as available for economic dispatch, excluding emergency MW (59.1 percent less 3.7 percent).

21 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 of owners and the small number of units.

Table 3-11 Distribution of MW for dispatchable unit offer prices: January 1 through September 30, 2017

	Dispatchable (Range)							
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	0.1%	79.8%	0.2%	0.1%	0.0%	0.0%	5.7%	86.0%
CT	0.0%	84.2%	5.2%	1.0%	0.0%	0.1%	8.6%	99.0%
Diesel	0.1%	39.5%	18.8%	2.3%	0.1%	0.0%	15.1%	76.0%
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	6.4%	0.0%	0.0%	0.0%	0.0%	0.0%	6.4%
Pumped Storage	66.9%	1.5%	0.0%	0.0%	0.0%	0.0%	1.4%	69.8%
Run of River	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Solar	53.8%	2.6%	0.0%	0.0%	0.0%	0.0%	0.0%	56.4%
Steam	0.1%	50.4%	0.1%	0.0%	0.0%	0.4%	2.5%	53.5%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	55.4%	9.5%	0.0%	0.0%	0.0%	0.0%	0.5%	65.3%
All Dispatchable Offers	2.8%	51.1%	1.1%	0.2%	0.0%	0.1%	3.7%	59.1%

Table 3-12 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 2017. For example, 10.6 percent of CC offers were self scheduled and dispatchable and in the $0 to $200 offer price range. The total column is the proportion of all MW offers by unit type that were self scheduled to generate fixed output or are self scheduled and dispatchable. For example, 14.0 percent of all CC MW offers were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including the 1.6 percent of emergency MW offered by CC units. The all self scheduled offers row is the proportion of MW that were offered as either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum within a given range by all unit types. For example, units that were self scheduled to generate at fixed output accounted for 18.8 percent of all offers and self scheduled and dispatchable units accounted for 19.7 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 2017, 20.0 percent were offered as self scheduled and 20.9 percent were offered as self scheduled and dispatchable.

Table 3-12 Distribution of MW for self scheduled and dispatchable unit offer prices: January 1 through September 30, 2017

	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	1.6%	0.3%	0.2%	10.6%	0.0%	0.0%	0.0%	0.0%	1.3%	14.0%
CT	0.2%	0.1%	0.0%	0.6%	0.0%	0.0%	0.0%	0.0%	0.1%	1.0%
Diesel	20.2%	1.1%	2.5%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	24.0%
Fuel Cell	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Nuclear	79.4%	1.1%	9.2%	3.7%	0.0%	0.0%	0.0%	0.0%	0.1%	93.6%
Pumped Storage	14.8%	9.9%	2.5%	0.0%	0.0%	0.0%	0.0%	0.0%	3.0%	30.2%
Run of River	61.9%	16.3%	0.4%	18.5%	0.0%	0.0%	0.0%	0.0%	2.6%	99.8%
Solar	28.6%	10.6%	4.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	43.6%
Steam	3.9%	1.2%	0.2%	39.2%	0.0%	0.0%	0.0%	0.0%	1.9%	46.5%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	3.2%	2.5%	23.1%	2.7%	0.0%	0.0%	0.0%	0.0%	3.2%	34.7%
All Self-Scheduled Offers	18.8%	1.3%	2.4%	17.3%	0.0%	0.0%	0.0%	0.0%	1.2%	40.9%

Fuel Diversity

Figure 3-8 shows the fuel diversity index (FDI_e) for PJM energy generation.[22] The FDI_e is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the share of fuel type i. The minimum possible value for the FDI_e is zero, corresponding to all generation from a single fuel type. The maximum possible value for the FDI_e is achieved when each fuel type has an equal share of total generation. For a generation fleet composed of 10 fuel types, the maximum achievable index is 0.9. The fuel type categories used in the calculation of the FDI_e are the 10 primary fuel sources in Table 3-9 with nonzero generation values. The FDI_e exhibited seasonality in prior years with most of the peaks occurring in the spring and summer months, and the valleys occurring in the fall and winter months. As fuel diversity has increased, the seasonality in the FDI_e has decreased and the FDI_e has exhibited less volatility. A significant drop in the FDI_e occurred in the fall of 2004 as a result of the expansion of the PJM market footprint into ComEd, AEP, and Dayton Power & Light control zones and the increased shares of coal and nuclear that resulted.[23] The increasing trend that began in 2008 corresponds to a period of decreasing coal generation, increasing gas generation and increasing wind generation. Coal generation as a share of total generation dropped 20.5 percentage points from 2008 to 2016 and gas generation increased 19.3 percentage points. Wind generation was 2.2 percent of total generation in 2016 and 0.5 percent of total generation in 2008, an increase of 1.7 percentage points. The average FDI_e increased 0.7 percent from the first nine months of 2016 to the first nine months of 2017.

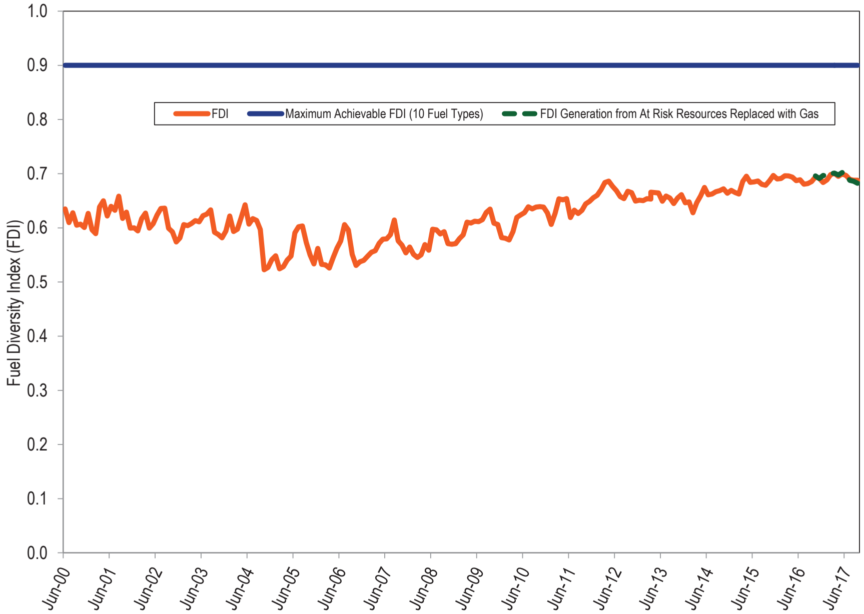
The FDI_e was used to measure the impact of potential retirements by resources that have been identified as being at risk of retirement by the MMUs net revenue adequacy analysis.[24] There were 96 resources with installed capacity totaling 14,500 MW identified as at risk. The 96 at risk resources generated 41.7 GWh in the twelve month period ending September 30, 2017, 39.6 GWh from coal and oil fired generators. The dashed line in Figure 3-8 shows the FDI_e calculated assuming that the 39.6 GWh of generation from coal and oil fired generators, identified as being at risk resources, were replaced by gas generation. The FDI_e under these assumptions would have increased in seven of the 12 months with an average monthly increase of 0.2 percent over the actual FDI_e.

22 Monitoring Analytics developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.

23 See the *2016 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton control zones occurred in October 2004.

24 See the *2016 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Units at Risk.

Figure 3-8 Fuel diversity index for PJM monthly generation: June 1, 2000 through September 30, 2017



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

The maximum of average offered real-time generation in the summer of 2017 increased by 2,551 MW, or 1.5 percent, from the summer of 2016, from 171,300 MW to 173,851MW.[25]

In the first nine months of 2017, 3,941.0 MW of new resources were added and 2,072.8 MW were retired.

PJM average real-time cleared generation in the first nine months of 2017 decreased by 1.2 percent from the first nine months of 2016, from 92,799 MW to 91,658 MW.[26]

PJM average real-time cleared supply including imports in the first nine months of 2017 decreased by 3.7 percent from the first nine months of 2016, from 96,907 MW to 93,322 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.

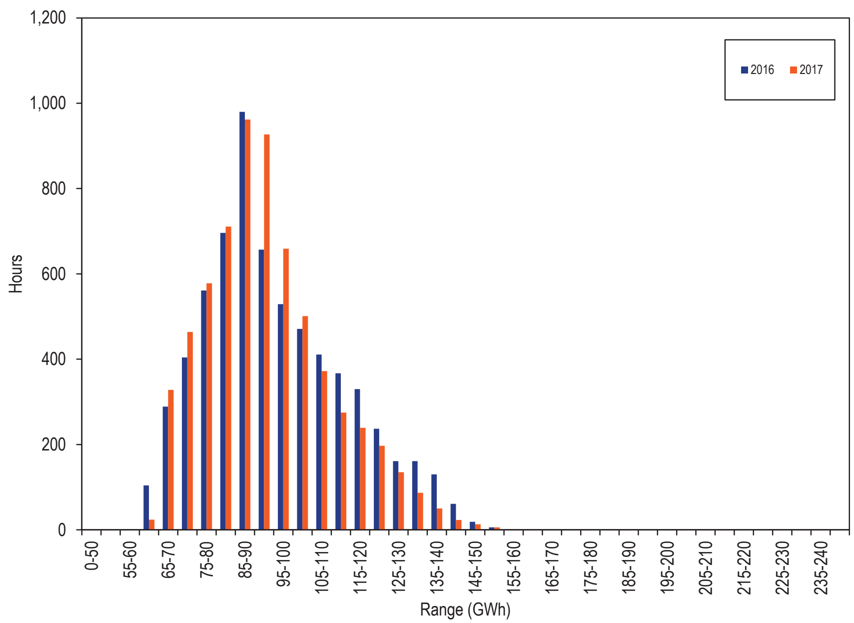
25 Calculated values shown in Section 3, "Energy Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.
26 Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

- 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 3-9 shows the hourly distribution of PJM real-time generation plus imports for the first nine months of 2016 and 2017.

Figure 3-9 Distribution of PJM real-time generation plus imports: January 1 through September 30, 2016 and 2017[27]



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

PJM Real-Time, Average Supply

Table 3-13 presents summary real-time supply statistics for the first nine months of each year for the 18-year period from 2000 through 2017.[28]

Table 3-13 PJM real-time average hourly generation and real-time average hourly generation plus average hourly imports: January 1 through September 30, 2000 through 2017

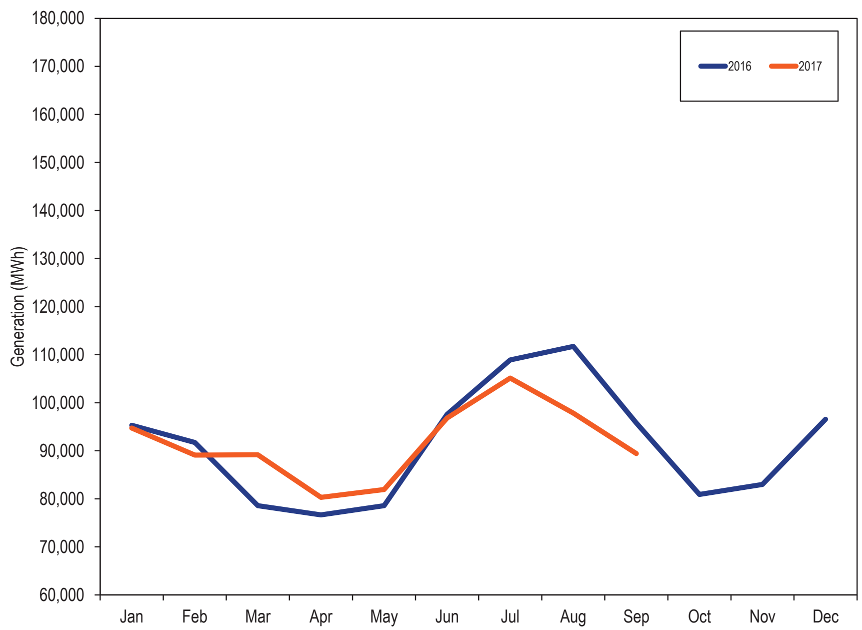
	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
Jan-Sep	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2000	30,989	5,216	33,855	5,966	NA	NA	NA	NA
2001	30,304	5,216	33,299	5,571	(2.2%)	0.0%	(1.6%)	(6.6%)
2002	34,467	8,217	38,207	8,540	13.7%	57.5%	14.7%	53.3%
2003	37,211	6,556	40,815	6,526	8.0%	(20.2%)	6.8%	(23.6%)
2004	45,888	11,035	49,990	11,185	23.3%	68.3%	22.5%	71.4%
2005	81,095	16,710	86,330	17,216	76.7%	51.4%	72.7%	53.9%
2006	84,260	14,696	88,621	15,399	3.9%	(12.1%)	2.7%	(10.5%)
2007	87,297	14,853	91,647	15,668	3.6%	1.1%	3.4%	1.7%
2008	85,241	14,203	90,621	14,646	(2.4%)	(4.4%)	(1.1%)	(6.5%)
2009	78,850	14,242	83,986	14,728	(7.5%)	0.3%	(7.3%)	0.6%
2010	84,086	16,346	88,876	17,001	6.6%	14.8%	5.8%	15.4%
2011	86,966	17,369	91,746	18,276	3.4%	6.3%	3.2%	7.5%
2012	90,367	16,893	95,726	17,810	3.9%	(2.7%)	4.3%	(2.5%)
2013	90,432	15,792	95,639	16,729	0.1%	(6.5%)	(0.1%)	(6.1%)
2014	92,449	16,002	97,922	17,064	2.2%	1.3%	2.4%	2.0%
2015	91,901	16,711	97,896	17,863	(0.6%)	4.4%	(0.0%)	4.7%
2016	92,799	19,003	96,907	19,067	1.0%	13.7%	(1.0%)	6.7%
2017	91,658	15,964	93,322	16,230	(1.2%)	(16.0%)	(3.7%)	(14.9%)

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

PJM Real-Time, Monthly Average Generation

Figure 3-10 compares the real-time, monthly average hourly generation in 2016 and the first nine months of 2017.

Figure 3-10 PJM real-time average monthly hourly generation: January 1, 2016 through September 30, 2017



Day-Ahead Supply

PJM average day-ahead cleared supply in the first nine months of 2017, including INCs and up to congestion transactions, increased by 0.2 percent from the first nine months of 2016, from 133,089 MW to 133,377 MW.

PJM average day-ahead cleared supply in the first nine months of 2017, including INCs, up to congestion transactions, and imports, decreased by 0.9 percent from the first nine months of 2016, from 134,881 MW to 133,695 MW.

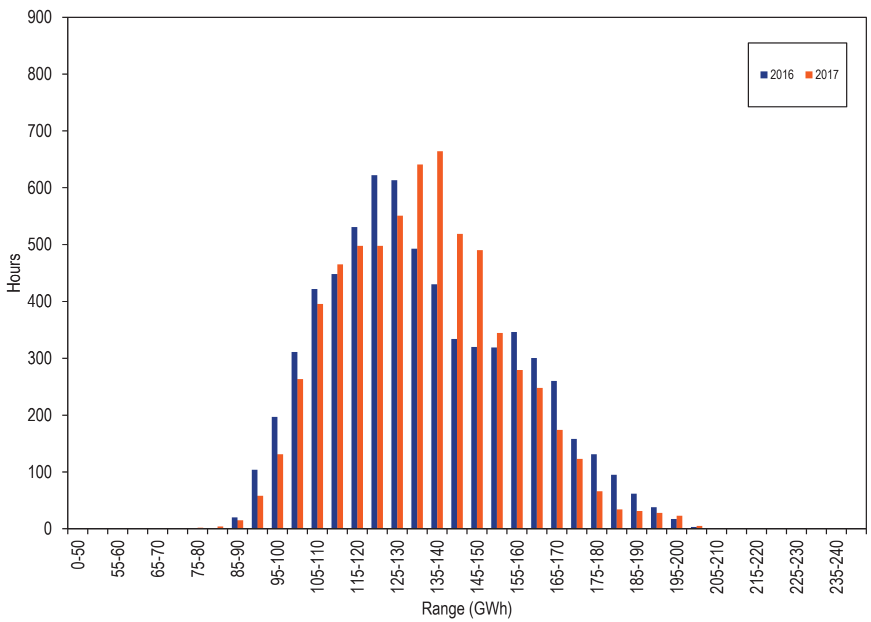
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **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 3-11 shows the hourly distribution of PJM day-ahead supply, including increment offers, up to congestion transactions, and imports for the first nine months of 2016 and 2017.

Figure 3-11 Distribution of PJM day-ahead supply plus imports: January 1 through September 30, 2016 and 2017[29]



PJM Day-Ahead, Average Supply

Table 3-14 presents summary day-ahead supply statistics for the first nine months of each year for the 18-year period from 2000 through 2017.[30]

Table 3-14 PJM day-ahead average hourly supply and day-ahead average hourly supply plus average hourly imports: January 1 through September 30, 2000 through 2017

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
Jan-Sep	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2000	27,853	5,340	28,233	5,395	NA	NA	NA	NA
2001	27,519	4,839	28,279	4,911	(1.2%)	(9.4%)	0.2%	(9.0%)
2002	30,080	10,982	30,629	10,992	9.3%	126.9%	8.3%	123.8%
2003	40,024	9,079	40,556	9,066	33.1%	(17.3%)	32.4%	(17.5%)
2004	56,103	13,380	56,799	13,349	40.2%	47.4%	40.0%	47.2%
2005	94,437	18,671	96,315	18,963	68.3%	39.5%	69.6%	42.1%
2006	100,888	18,061	103,029	18,071	6.8%	(3.3%)	7.0%	(4.7%)
2007	110,300	17,561	112,575	17,752	9.3%	(2.8%)	9.3%	(1.8%)
2008	107,367	16,601	109,811	16,717	(2.7%)	(5.5%)	(2.5%)	(5.8%)
2009	98,527	17,462	101,123	17,526	(8.2%)	5.2%	(7.9%)	4.8%
2010	108,309	23,295	111,059	23,464	9.9%	33.4%	9.8%	33.9%
2011	116,988	22,722	119,488	23,015	8.0%	(2.5%)	7.6%	(1.9%)
2012	135,213	18,553	137,670	18,788	15.6%	(18.3%)	15.2%	(18.4%)
2013	148,489	18,858	150,785	19,073	9.8%	1.6%	9.5%	1.5%
2014	161,137	23,922	163,431	24,080	8.5%	26.9%	8.4%	26.2%
2015	116,975	20,289	119,349	20,502	(27.4%)	(15.2%)	(27.0%)	(14.9%)
2016	133,089	23,414	134,881	23,403	13.8%	15.4%	13.0%	14.1%
2017	133,377	20,602	133,695	20,616	0.2%	(12.0%)	(0.9%)	(11.9%)

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

30 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.

PJM Day-Ahead, Monthly Average Supply

Figure 3-12 compares the day-ahead, monthly average hourly supply, including increment offers and up to congestion transactions, for 2016 and the first nine months of 2017.

Figure 3-12 PJM day-ahead monthly average hourly supply: January 1, 2016 through September 30, 2017

Real-Time and Day-Ahead Supply

Table 3-15 presents summary statistics for the first nine months of 2016 and 2017, for day-ahead and real-time supply. All data are cleared MW. The last two columns of Table 3-15 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 2017, up to congestion transactions were 27.3 percent of the total day-ahead supply compared to 25.5 percent in the first nine months of 2016.

Table 3-15 Day-ahead and real-time supply (MW): January 1 through September 30, 2016 and 2017

		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	2016	93,714	5,171	34,201	840	133,930	92,799	95,499	38,430	915
	2017	92,035	4,876	36,467	318	133,695	91,658	93,322	40,373	377
Median	2016	90,172	5,027	33,655	869	130,152	89,013	91,578	38,574	1,159
	2017	90,180	4,844	36,007	275	133,173	89,480	91,067	42,106	700
Standard Deviation	2016	19,435	1,054	6,936	795	23,325	19,003	18,525	4,800	432
	2017	16,644	1,498	8,567	207	20,616	15,964	16,230	4,386	680
Peak Average	2016	104,030	5,281	36,337	886	146,546	101,857	104,842	41,705	2,173
	2017	101,701	5,265	38,806	281	146,053	100,621	102,436	43,616	1,080
Peak Median	2016	102,122	5,146	35,655	859	145,102	98,442	102,414	42,688	3,680
	2017	98,144	5,222	38,446	234	143,967	96,861	99,062	44,905	1,283
Peak Standard Deviation	2016	17,542	1,019	6,660	871	20,911	18,233	17,137	3,774	(691)
	2017	14,088	1,475	8,356	204	16,641	14,170	14,374	2,267	(82)
Off-Peak Average	2016	84,307	5,071	32,254	799	122,425	84,539	86,980	35,445	(232)
	2017	83,245	4,522	34,339	351	122,458	83,506	85,034	37,424	(262)
Off-Peak Median	2016	81,898	4,903	31,398	874	119,175	81,922	84,714	34,461	(24)
	2017	81,136	4,510	33,531	314	119,843	81,253	82,654	37,189	(118)
Off-Peak Standard Deviation	2016	16,002	1,075	6,602	717	19,077	15,630	15,368	3,709	372
	2017	13,647	1,429	8,196	204	17,165	12,826	13,072	4,093	820

Figure 3-13 shows the average hourly cleared volumes of day-ahead supply and real-time supply for the first nine months of 2017. The day-ahead supply consists of cleared MW of day-ahead generation, imports, increment offers and up to congestion transactions. The real-time generation includes generation and imports.

Figure 3-13 Day-ahead and real-time supply (Average hourly volumes): January 1 through September 30, 2017

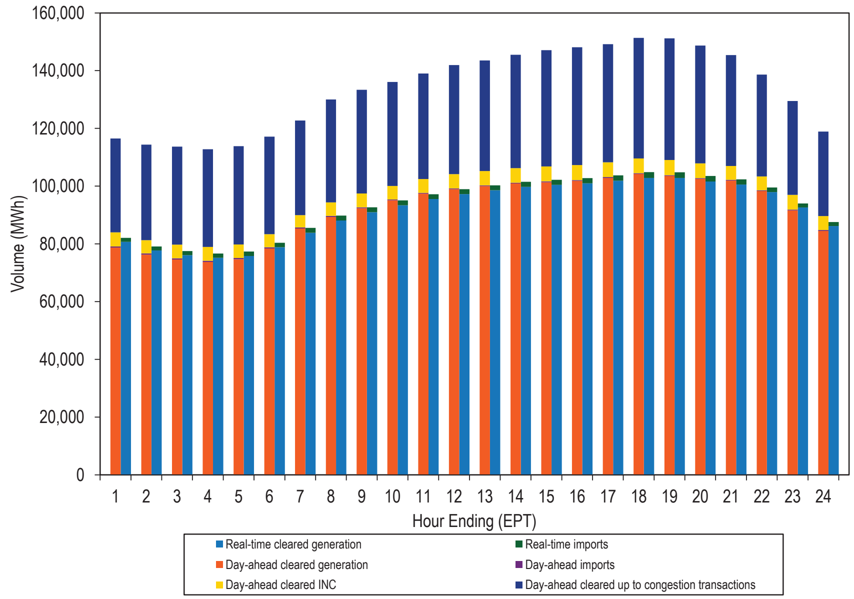


Figure 3-14 shows the difference between the day-ahead and real-time average daily supply for 2016 and the first nine months of 2017.

Figure 3-14 Difference between day-ahead and real-time supply (Average daily volumes): January 1, 2016 through September 30, 2017

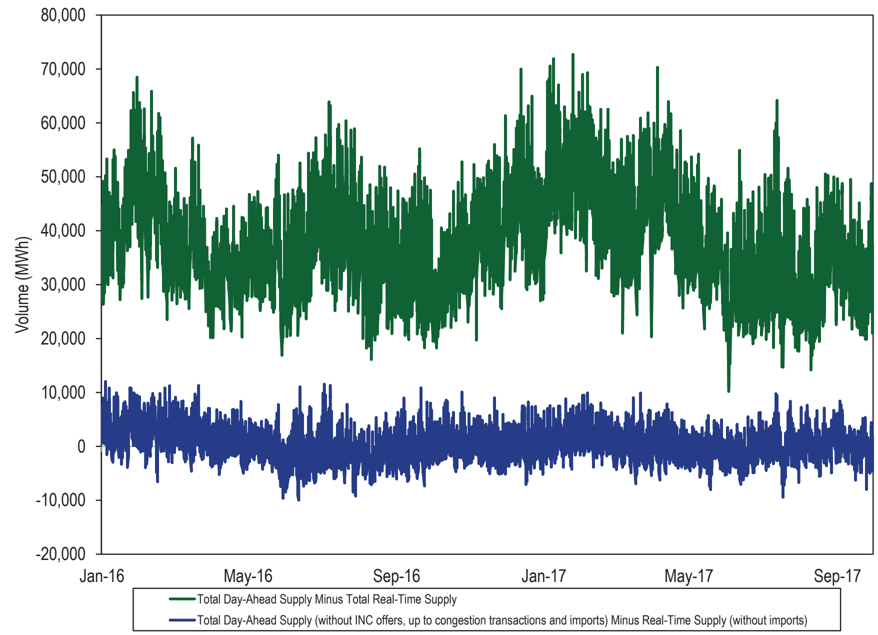
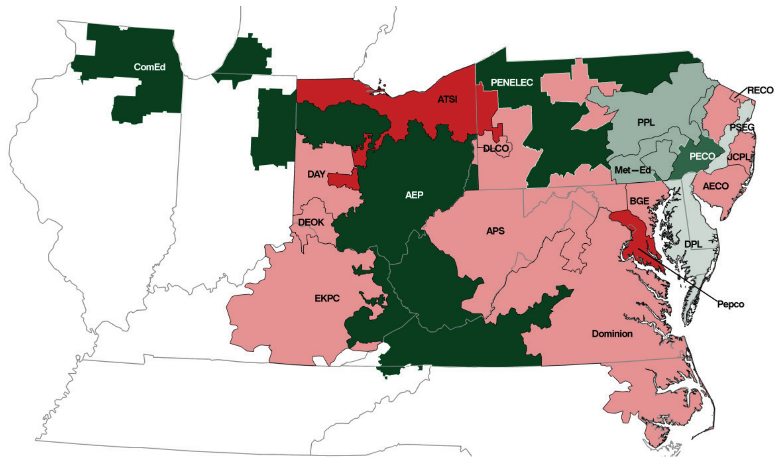


Figure 3-15 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2017. Figure 3-15 is color coded using a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation 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. Table 3-16 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2016 and 2017.

Figure 3-15 Map of PJM real-time generation, less real-time load, by zone: January 1 through September 30, 2017[31]



Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)
AECO	(2,600)	ComEd	24,233	DPL	(7,598)	PENELEC	20,339
AEP	21,706	DAY	(3,917)	EKPC	(3,205)	Pepco	(15,814)
APS	(524)	DEOK	(4,802)	JCPL	(2,669)	PPL	5,917
ATSI	(19,152)	DLCO	2,177	Met-Ed	5,291	PSEG	1,232
BGE	(8,117)	Dominion	(1,223)	PECO	18,747	RECO	(1,096)

Table 3-16 PJM real-time generation less real-time load by zone (GWh): January 1 through September 30, 2016 and 2017

	Zonal Generation and Load (GWh)					
	2016			2017		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	5,195.8	7,936.3	(2,740.5)	4,899.3	7,499.2	(2,599.9)
AEP	107,334.2	96,377.8	10,956.4	114,158.4	92,452.2	21,706.2
APS	35,689.9	36,411.3	(721.4)	34,647.6	35,171.9	(524.3)
ATSI	32,444.5	51,198.8	(18,754.3)	30,025.8	49,178.0	(19,152.2)
BGE	16,707.9	24,265.5	(7,557.6)	14,772.8	22,889.4	(8,116.6)
ComEd	96,426.6	75,186.5	21,240.1	95,716.8	71,484.1	24,232.7
DAY	11,558.1	13,185.0	(1,626.8)	8,697.8	12,614.6	(3,916.7)
DEOK	11,615.0	20,945.1	(9,330.1)	15,071.4	19,873.9	(4,802.5)
DLCO	13,229.8	10,672.7	2,557.0	12,320.7	10,143.4	2,177.2
Dominion	75,782.2	73,832.2	1,950.0	70,692.7	71,915.3	(1,222.7)
DPL	6,769.1	14,031.5	(7,262.4)	5,847.9	13,446.0	(7,598.1)
EKPC	7,690.8	9,550.0	(1,859.2)	5,822.5	9,027.8	(3,205.3)
JCPL	13,594.9	17,705.2	(4,110.3)	14,184.4	16,853.2	(2,668.9)
Met-Ed	17,425.0	11,618.3	5,806.8	16,578.8	11,288.2	5,290.6
PECO	49,379.9	30,884.9	18,494.9	48,514.8	29,768.2	18,746.6
PENELEC	27,295.5	12,697.9	14,597.7	32,814.0	12,474.7	20,339.4
Pepco	8,531.3	23,478.2	(14,946.9)	6,383.8	22,198.1	(15,814.3)
PPL	38,342.7	30,561.7	7,781.0	35,461.3	29,544.3	5,916.9
PSEG	35,140.4	33,845.3	1,295.2	33,838.1	32,605.8	1,232.3
RECO	0.0	1,154.3	(1,154.3)	0.0	1,095.6	(1,095.6)

Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

In this section, demand refers to accounting load and exports and in the Day-Ahead Energy Market also includes virtual transactions.[32]

The PJM system real-time peak load in the first nine months of 2017 was 145,635.9 MW in the HE 1800 on July 19, 2017, which was 6,541 MW, or 4.3 percent, lower than the peak load in the first nine months of 2016, which was 152,176.9 MW in the HE 1600 on August 11 ,2016.

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

32 PJM reports peak load including accounting load plus an addback equal to PJM's estimated load drop from demand side resources. This will generally result in PJM reporting peak load values greater than accounting load values. PJM's load drop estimate is based PJM Manual 19: Load Forecasting and Analysis Attachment A: Load Drop Estimate Guidelines at <http://www.pjm.com/~/media/documents/manuals/m19.ashx>.

Table 3-17 shows the peak loads for the first nine months of 1999 through 2017.

Table 3-17 Actual PJM footprint peak loads: January through September, 1999 to 2017[33]

(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%
2016	Thu, August 11	16	152,177	8,480	5.9%
2017	Wed, July 19	18	145,636	(6,541)	(4.3%)

Figure 3-16 shows the peak loads for the first nine months of 1999 through 2017.

Figure 3-16 PJM footprint calendar year peak loads: January 1 through September 30, 1999 to 2017

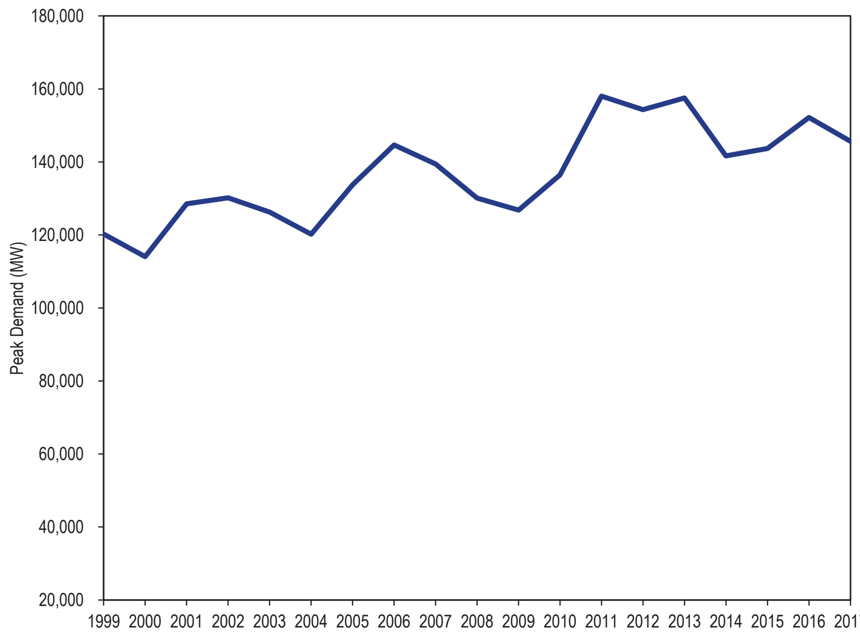
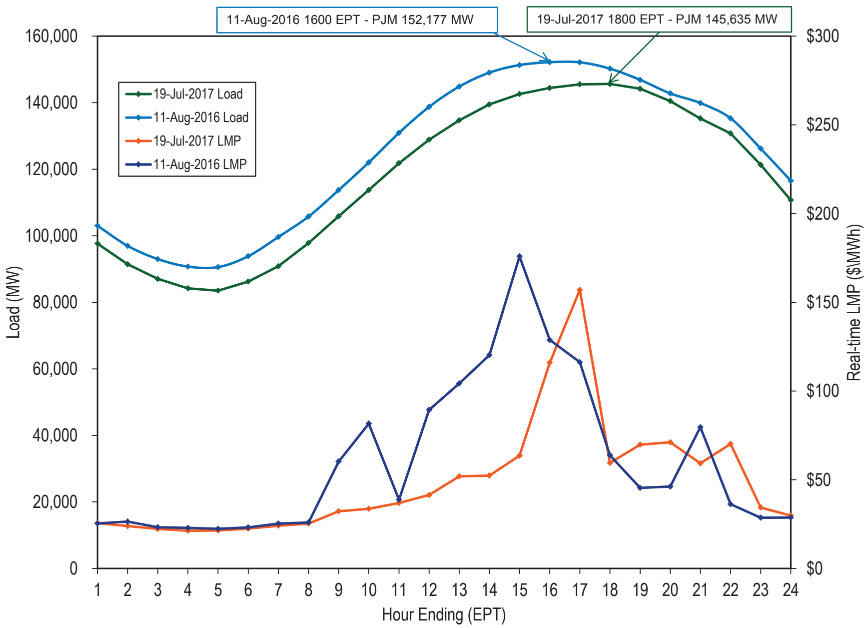


Figure 3-17 compares the peak load days during the first nine months of 2016 and 2017. The average real-time LMP for the July 19, 2017 peak load hour was $59.49 and for the August 11, 2016 peak load hour was $128.83.

33 Peak loads shown are Power accounting 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 3-17 PJM peak-load comparison Thursday, August 11, 2016 and Wednesday, July 19, 201



Real-Time Demand

PJM average real-time load in the first nine months of 2017 decreased by 3.7 percent from the first nine months of 2016, from 90,599 MW to 87,243 MW.[34]

PJM average real-time demand including export, in the first nine months of 2017 decreased by 3.9 percent from the first nine months of 2016, from 95,340 MW to 91,616 MW.

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

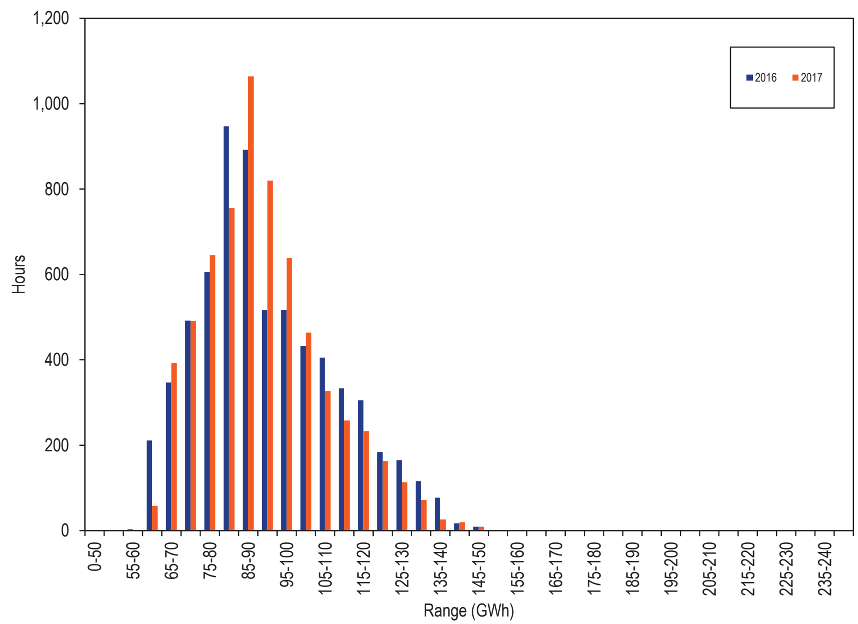
- Load. The actual MWh level of energy used by load within PJM.
- Export. An export is an external energy transaction scheduled from PJM to another balancing authority. A real-time export must have a valid OASIS reservation when offered, must have available ramp room to support the export, must be accompanied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

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

PJM Real-Time Demand Duration

Figure 3-18 shows the hourly distribution of PJM real-time load plus exports for the first nine months of 2016 and 2017.[35]

Figure 3-18 Distribution of PJM real-time accounting load plus exports: January 1 through September 30, 2016 and 2017[36]



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

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

PJM Real-Time, Average Load

Table 3-18 presents summary real-time demand statistics for the first nine months of 1998 to 2017. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through marginal loss pricing.[37]

Table 3-18 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: January 1 through September 30, 1998 through 2017[38]

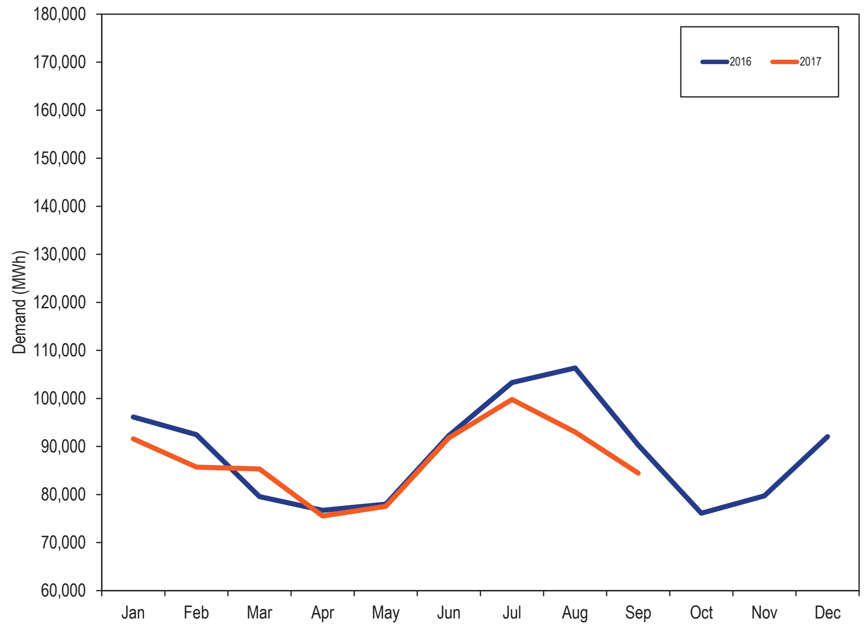
	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Jan-Sep	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
1998	29,112	5,780	29,112	5,780	NA	NA	NA	NA
1999	30,236	6,306	30,236	6,306	3.9%	9.1%	3.9%	9.1%
2000	30,266	5,765	31,060	5,977	0.1%	(8.6%)	2.7%	(5.2%)
2001	31,060	6,156	32,900	5,861	2.6%	6.8%	5.9%	(2.0%)
2002	35,715	8,688	37,367	8,878	15.0%	41.1%	13.6%	51.5%
2003	37,996	7,187	39,965	7,120	6.4%	(17.3%)	7.0%	(19.8%)
2004	45,294	10,512	49,176	11,556	19.2%	46.3%	23.0%	62.3%
2005	78,235	17,541	85,295	17,794	72.7%	66.9%	73.4%	54.0%
2006	80,717	15,568	87,326	16,147	3.2%	(11.2%)	2.4%	(9.3%)
2007	83,114	15,386	89,390	16,008	3.0%	(1.2%)	2.4%	(0.9%)
2008	80,611	14,389	87,788	14,893	(3.0%)	(6.5%)	(1.8%)	(7.0%)
2009	76,954	13,879	82,118	14,360	(4.5%)	(3.5%)	(6.5%)	(3.6%)
2010	81,068	16,209	86,994	16,687	5.3%	16.8%	5.9%	16.2%
2011	83,762	17,604	89,628	17,799	3.3%	8.6%	3.0%	6.7%
2012	88,687	17,431	93,763	17,329	5.9%	(1.0%)	4.6%	(2.6%)
2013	89,123	16,384	93,647	16,254	0.5%	(6.0%)	(0.1%)	(6.2%)
2014	90,567	16,662	96,015	16,518	1.6%	1.7%	2.5%	1.6%
2015	91,857	17,211	96,102	17,300	1.4%	3.3%	0.1%	4.7%
2016	90,599	18,183	95,340	18,571	(1.4%)	5.6%	(0.8%)	7.3%
2017	87,243	16,008	91,616	15,811	(3.7%)	(12.0%)	(3.9%)	(14.9%)

37 Accounting load is used here because PJM uses accounting load in the settlement process, which determines how much load customers pay for. In addition, the use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP, which excluded losses prior to June 1 and includes losses after June 1.
38 Export data are not available before June 1, 2000. The export data for 2000 are for the last six months of 2000.

PJM Real-Time, Monthly Average Load

Figure 3-19 compares the real-time, monthly average hourly loads for 2016 and the first nine months of 2017.

Figure 3-19 PJM real-time monthly average hourly load: January 1, 2016 through September 30, 2017



PJM real-time load is significantly affected by temperature. Figure 3-20 and Table 3-19 compare the PJM monthly heating and cooling degree days in 2016 and the first nine months of 2017.[39] Heating degree days decreased 16.3 percent from the first nine months of 2016 to 2017.

39 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings). 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

Figure 3-20 PJM heating and cooling degree days: January 1, 2016 through September 30, 2017

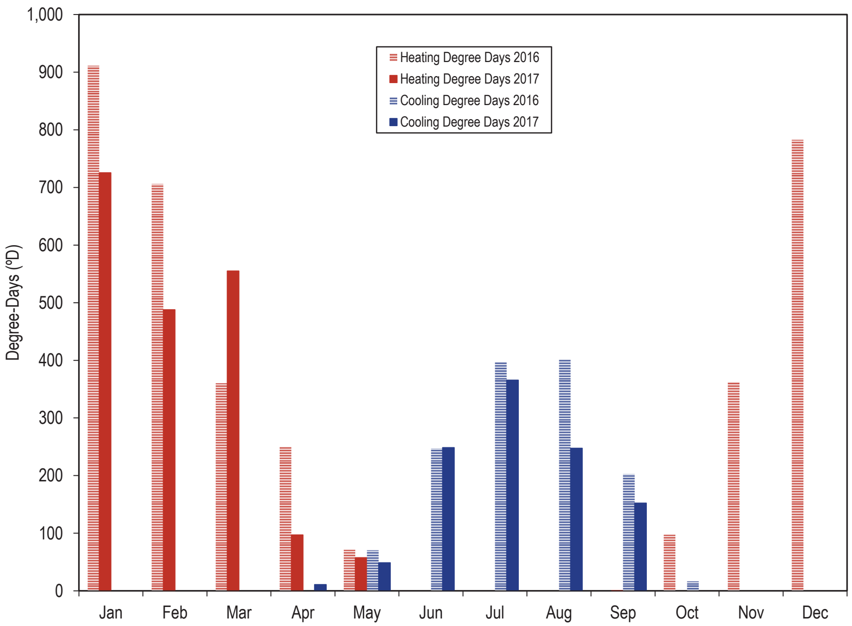


Table 3-19 PJM heating and cooling degree days: January 2016 through September, 2017

	2016		2017		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	911	0	725	0	(20.4%)	0.00%
Feb	706	0	488	0	(30.9%)	0.00%
Mar	360	0	555	0	54.1%	0.00%
Apr	250	1	97	11	(61.0%)	1,375.86%
May	71	71	58	49	(18.9%)	(30.64%)
Jun	0	247	0	249	0.0%	0.59%
Jul	0	397	0	366	0.0%	(7.95%)
Aug	0	402	0	248	0.0%	(38.32%)
Sep	0	203	1	152	0.0%	(24.83%)
Oct	98	17				
Nov	363	0				
Dec	782	0				
Jan-Sep	2,298	1,320	1,924	1,074	(16.3%)	(18.62%)

Day-Ahead Demand

PJM average day-ahead demand in the first nine months of 2017, including DECs and up to congestion transactions, decreased by 0.5 percent from the first nine months of 2016, from 129,070 MW to 128,450 MW.

PJM average day-ahead demand in the first nine months of 2017, including DECs, up to congestion transactions, and exports, decreased by 1.0 percent from the first nine months of 2016, from 132,607 MW to 131,264 MW.

The reduction in up to congestion transactions (UTC) that had followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed. There was an increase in up to congestion volume as a result of the expiration of the 15 month refund period for the proceeding related to uplift charges for UTC transactions.[40]

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.

40 148 FERC ¶ 61,144 (2014).

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

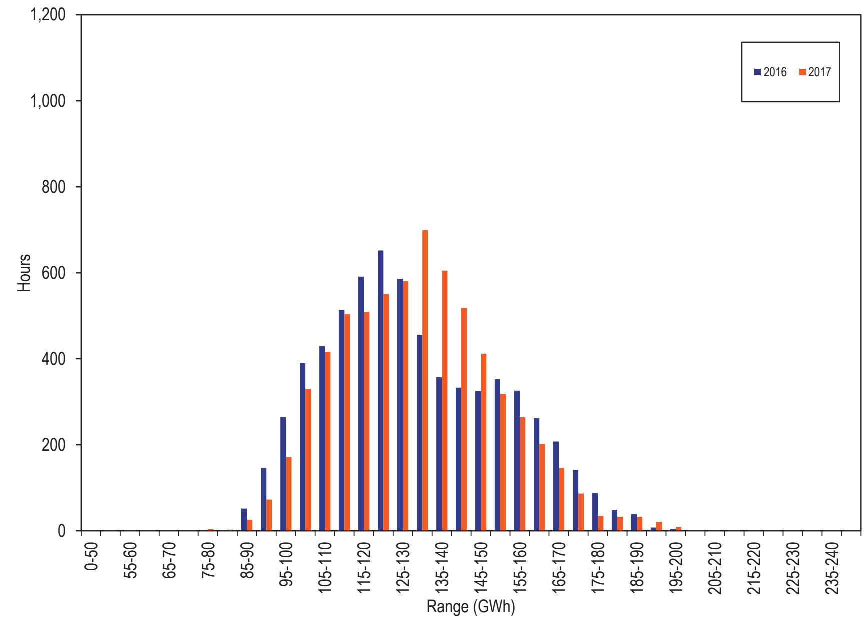
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of 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 3-21 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up to congestion transactions, and exports for the first nine months of 2016 and 2017.

Figure 3-21 Distribution of PJM day-ahead demand plus exports: January 1 through September 30, 2016 and 2017[41]



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

PJM Day-Ahead, Average Demand

Table 3-20 presents summary day-ahead demand statistics for the first nine months of each year from 2000 to 2017.[42]

Table 3-20 PJM day-ahead average demand and day-ahead average hourly demand plus average hourly exports: January 1 through September 30, 2000 through 2017

	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
Jan-Sep	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2000	34,064	7,649	34,268	7,553	NA	NA	NA	NA
2001	33,944	7,016	34,444	6,817	(0.4%)	(8.3%)	0.5%	(9.7%)
2002	41,634	11,073	41,726	11,120	22.7%	57.8%	21.1%	63.1%
2003	45,371	8,377	45,477	8,354	9.0%	(24.4%)	9.0%	(24.9%)
2004	55,830	13,319	56,558	13,753	23.1%	59.0%	24.4%	64.6%
2005	93,525	19,126	96,302	19,455	67.5%	43.6%	70.3%	41.5%
2006	99,403	18,165	102,520	18,687	6.3%	(5.0%)	6.5%	(3.9%)
2007	107,295	17,580	110,711	17,949	7.9%	(3.2%)	8.0%	(4.0%)
2008	103,586	16,618	107,169	16,810	(3.5%)	(5.5%)	(3.2%)	(6.3%)
2009	96,020	16,995	99,084	17,117	(7.3%)	2.3%	(7.5%)	1.8%
2010	105,018	22,972	109,113	23,286	9.4%	35.2%	10.1%	36.0%
2011	113,724	22,444	117,533	22,651	8.3%	(2.3%)	7.7%	(2.7%)
2012	132,494	18,115	135,840	18,235	16.5%	(19.3%)	15.6%	(19.5%)
2013	145,139	18,667	148,444	18,696	9.5%	3.1%	9.3%	2.5%
2014	156,542	23,584	160,425	23,533	7.9%	26.3%	8.1%	25.9%
2015	113,553	19,788	117,090	19,951	(27.5%)	(16.1%)	(27.0%)	(15.2%)
2016	129,070	22,508	132,607	22,817	13.7%	13.7%	13.3%	14.4%
2017	128,450	20,002	131,264	20,067	(0.5%)	(11.1%)	(1.0%)	(12.1%)

PJM Day-Ahead, Monthly Average Demand

Figure 3-22 compares the day-ahead, monthly average hourly demand, including decrement bids and up to congestion transactions in 2016 and the first nine months of 2017

Figure 3-22 PJM day-ahead monthly average hourly demand: January 1, 2016 through September 30, 2017

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

Real-Time and Day-Ahead Demand

Table 3-21 presents summary statistics for the first nine months of 2016 and 2017 day-ahead and real-time demand. All data are cleared MW. The last two columns of Table 3-21 are the day-ahead demand minus the real-time demand. The first such column is the total day-ahead demand less the total real-time demand and the second such column is the total physical day-ahead load (fixed demand plus price-sensitive demand) less the physical real-time load.

Table 3-21 Cleared day-ahead and real-time demand (MWh): January 1 through September 30, 2016 and 2017

		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	2016	86,989	3,134	4,743	34,201	1,404	130,474	90,599	92,568	37,906	52,693
	2017	84,661	2,925	4,397	36,467	2,814	131,264	87,243	91,616	39,647	47,595
Median	2016	83,781	3,122	4,494	33,655	1,457	127,047	86,646	88,703	38,344	48,302
	2017	82,853	2,901	4,383	36,007	2,694	130,754	85,019	89,413	41,341	43,678
Standard Deviation	2016	16,989	412	1,422	6,936	1,225	22,408	18,183	17,874	4,535	13,648
	2017	15,347	437	1,282	8,567	913	20,067	16,008	15,811	4,255	11,752
Peak Average	2016	96,483	3,398	5,124	36,337	1,418	142,773	99,962	101,873	40,900	59,063
	2017	93,811	3,202	4,670	38,806	2,848	143,336	96,230	100,517	42,819	53,411
Peak Median	2016	94,579	3,364	4,950	35,655	1,538	141,302	97,178	99,470	41,832	55,345
	2017	91,183	3,137	4,675	38,446	2,723	141,310	93,035	97,213	44,097	48,938
Peak Standard Deviation	2016	15,104	323	1,411	6,660	1,199	19,821	16,657	16,253	3,569	13,088
	2017	13,034	390	1,200	8,356	958	16,196	14,107	13,988	2,208	11,899
Off-Peak Average	2016	78,331	2,893	4,395	32,254	1,392	119,259	82,061	84,083	35,176	46,885
	2017	76,340	2,674	4,148	34,339	2,784	120,286	79,070	83,523	36,763	42,307
Off-Peak Median	2016	76,211	2,843	4,145	31,398	1,399	116,091	79,399	81,454	34,637	44,762
	2017	74,224	2,618	4,023	33,531	2,669	117,808	76,784	81,251	36,557	40,228
Off-Peak Standard Deviation	2016	13,662	329	1,340	6,602	1,248	18,388	15,043	14,799	3,589	11,453
	2017	12,243	307	1,303	8,196	868	16,652	12,965	12,724	3,928	9,037

Figure 3-23 shows the average hourly cleared volumes of day-ahead demand and real-time demand for the first nine months of 2017. The day-ahead demand includes day-ahead load, day-ahead exports, decrement bids and up to congestion transactions. The real-time demand includes real-time load and real-time exports.

Figure 3-23 Day-ahead and real-time demand (Average hourly volumes): January 1 through September 30, 2017

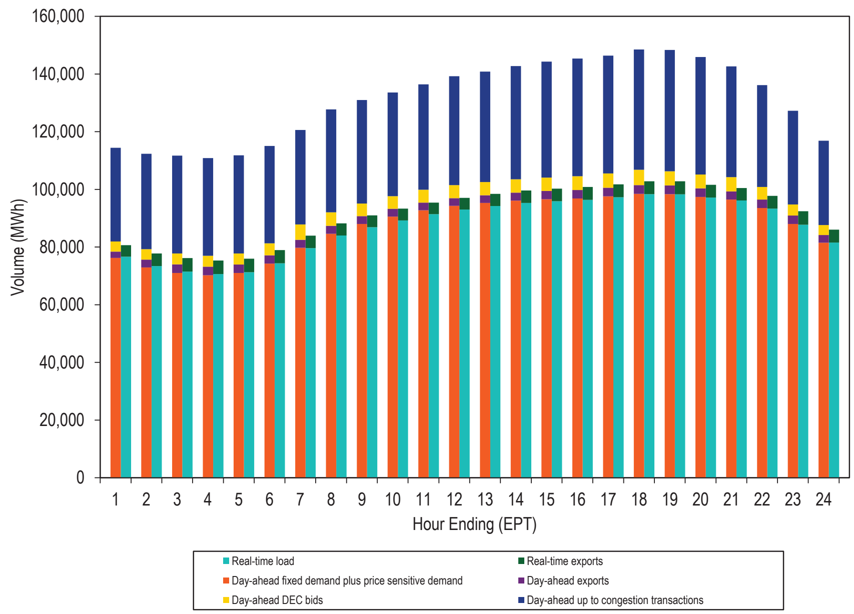
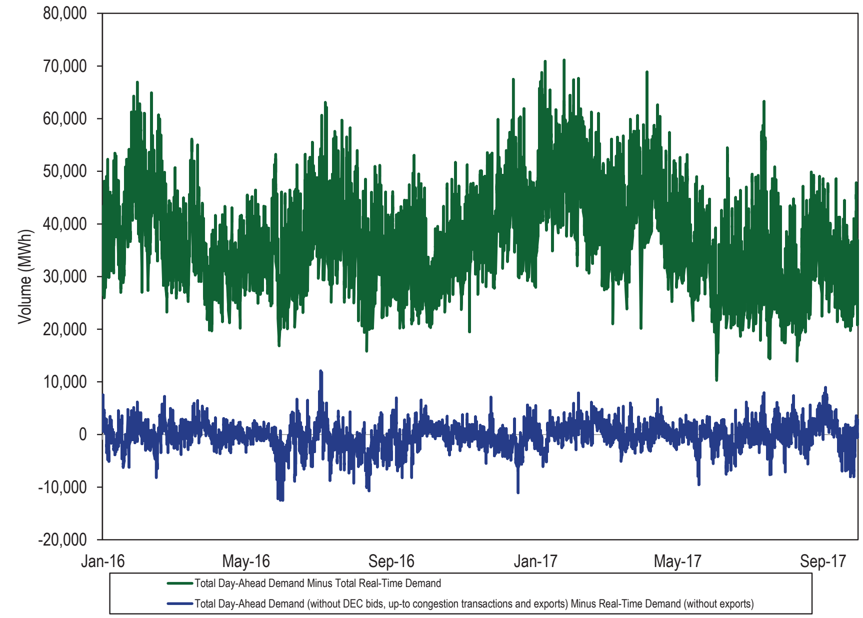


Figure 3-24 shows the difference between the day-ahead and real-time average daily demand from January 2016 through September 2017.

Figure 3-24 Difference between day-ahead and real-time demand (Average daily volumes): January 1, 2016 through September 30, 2017



Supply and Demand: Load and Spot Market

Real-Time Load and Spot Market

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

Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In addition to directly serving load, load serving entities can also transfer their responsibility to serve load to other parties through eSchedules transactions referred to as wholesale load responsibility (WLR) or retail load responsibility (RLR) transactions. When the responsibility to serve load is transferred via a bilateral contract, the entity to which the responsibility is transferred becomes the load serving entity. Supply from its own generation (self-supply) means that the parent company is generating power from plants that it owns in order to meet demand. Supply from bilateral purchases means that the parent company is purchasing power under bilateral contracts from a nonaffiliated 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 3-22 shows the monthly average share of real-time load served by self-supply, bilateral contracts and spot purchase in the first nine months of 2016 and 2017 based on parent company. In the first nine months of 2017, 15.5 percent of real-time load was supplied by bilateral contracts, 28.5 percent by spot market purchase and 56.0 percent by self-supply. Compared with the first nine months of 2016, reliance on bilateral contracts increased by 2.6 percentage points, reliance on spot supply increased by 4.6 percentage points and reliance on self-supply decreased by 7.2 percentage points.

Table 3-22 Monthly average percent of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: January 1 through September 30, 2016 and 2017[43]

	2016			2017			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	11.1%	25.9%	63.0%	16.5%	25.6%	57.9%	5.4%	(0.3%)	(5.1%)
Feb	11.5%	25.5%	63.0%	17.9%	25.2%	56.9%	6.4%	(0.3%)	(6.1%)
Mar	11.7%	26.4%	61.9%	14.9%	27.2%	57.9%	3.2%	0.8%	(4.0%)
Apr	12.7%	24.0%	63.4%	14.4%	32.4%	53.2%	1.7%	8.4%	(10.1%)
May	12.6%	24.5%	62.9%	14.3%	31.7%	54.0%	1.7%	7.2%	(8.9%)
Jun	12.5%	24.2%	63.2%	13.5%	32.7%	53.8%	1.0%	8.4%	(9.4%)
Jul	12.8%	23.3%	63.9%	17.1%	24.7%	58.3%	4.3%	1.4%	(5.6%)
Aug	12.7%	23.6%	63.7%	17.6%	24.0%	58.5%	4.8%	0.4%	(5.2%)
Sep	12.4%	22.7%	64.9%	16.0%	27.7%	56.4%	3.6%	4.9%	(8.5%)
Jan~Sep	12.9%	23.9%	63.2%	15.5%	28.5%	56.0%	2.6%	4.6%	(7.2%)

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 3-23 shows the monthly average share of day-ahead demand served by self-supply, bilateral contracts and spot purchases in the first nine months of 2016 and 2017, based on parent companies. In the first nine months of 2017, 9.4 percent of day-ahead demand was supplied by bilateral contracts, 22.2 percent by spot market purchases, and 68.4 percent by self-supply. Compared with the first nine months of 2016, reliance on bilateral contracts increased by 0.5 percentage points, reliance on spot supply

43 Table 3-22 and Table 3-23 were calculated as of October 18, 2017. The values may change slightly as billing values are updated by PJM.

decreased by 0.8 percentage points, and reliance on self-supply increased by 0.3 percentage points.

Table 3-23 Monthly average share of day-ahead self-supply demand, bilateral supply demand, and spot-supply demand based on parent companies: January 1 through September 30, 2016 and 2017

	2016			2017			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	8.2%	25.2%	66.6%	10.8%	20.5%	68.7%	2.6%	(4.8%)	2.1%
Feb	8.5%	24.8%	66.7%	11.0%	20.6%	68.4%	2.6%	(4.3%)	1.7%
Mar	7.9%	26.5%	65.6%	9.2%	21.9%	68.9%	1.2%	(4.6%)	3.4%
Apr	9.9%	23.9%	66.2%	8.3%	22.0%	69.6%	(1.6%)	(1.9%)	3.5%
May	9.6%	24.1%	66.3%	7.8%	22.3%	69.9%	(1.8%)	(1.8%)	3.6%
Jun	8.3%	21.9%	69.8%	8.6%	23.6%	67.8%	0.3%	1.7%	(2.0%)
Jul	8.6%	22.3%	69.0%	9.4%	23.2%	67.4%	0.8%	0.9%	(1.7%)
Aug	8.5%	22.3%	69.3%	9.8%	22.9%	67.3%	1.3%	0.7%	(2.0%)
Sep	7.9%	22.2%	70.0%	9.1%	22.8%	68.1%	1.2%	0.6%	(1.9%)
Jan~Sep	8.8%	23.1%	68.1%	9.4%	22.2%	68.4%	0.5%	(0.8%)	0.3%

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 local market power mitigation to situations where the local 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 mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test. There is no tariff or manual language that defines in detail the application of the TPS test and offer capping in the Day-Ahead Energy Market and the Real-Time 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 resolved 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. In the Day-Ahead Energy Market, PJM commits a unit on the schedule that results in the lower overall system production cost. In the Real-Time Energy Market, PJM uses a dispatch cost formula to compare price-based offers and cost-based offers to select the cheaper offer.[44] Dispatch cost is calculated as:

{(Incremental Energy Offer@EcoMin × EcoMin MW) + No Load Cost}× Min Run Time + Start Cost

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 3-25 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 that has a lower dispatch cost, even though the price-based offer is higher than cost-based offer at higher output levels and includes positive markups, inconsistent with the explicit goal of local market power mitigation.

44 See PJM OA Schedule 1 § 6.4.1 (g).

Figure 3-25 Offers with varying markups at different MW output levels

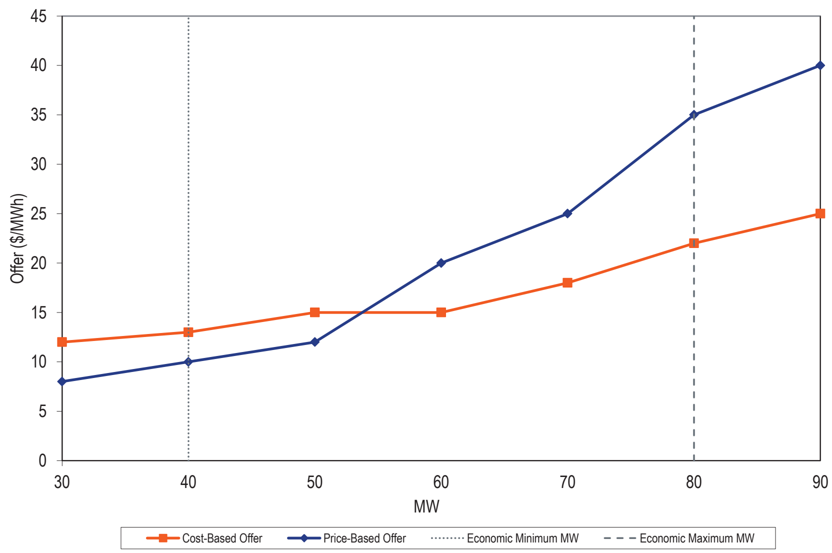


Table 3-24 shows the number and percent of unit schedule hours, by month, when units offered with crossing curves in the PJM Day-Ahead and Real-Time Energy Markets resulted in the dispatch cost being lower for the price-based offer than the cost-based offer, in the first nine months of 2017. The analysis only includes price-based units because the determination of the cheaper of price-based and cost-based offers is required to be made only if a unit elects to offer both cost-based and price-based offers. Units in PJM are only required to submit cost-based offers, and they may elect to offer price-based offers, but are not required to do so.

Offering a different economic minimum MW level, different minimum run times, different start up and notification times in the cost-based and price-based offers can also be used to avoid mitigation. For example, a unit may offer its price-based offer with a positive markup, but have a shorter minimum run time (MRT) in the price-based offer resulting in a lower dispatch cost for the price-based offer but setting prices at a level that includes a positive markup. Table 3-25 shows the number and percent of unit schedule hours when units offered lower minimum run times in price-based offers than in cost-based offers while having a positive markup that resulted in the dispatch cost being lower for the price-based offer.

Table 3-24 Units offered with crossing curves in the Day-Ahead and Real-Time Energy Markets: January 1 through September 30, 2017

	Day-Ahead			Real-Time		
2017	Number of Schedule Hours with Crossing Curves	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Crossing Curves	Number of Schedule Hours with Crossing Curves	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Crossing Curves
Jan	21,600	803,424	2.7%	19,381	803,424	2.4%
Feb	20,435	729,264	2.8%	19,318	729,264	2.6%
Mar	22,429	806,810	2.8%	20,547	806,810	2.5%
Apr	18,940	792,480	2.4%	17,970	792,480	2.3%
May	18,797	822,552	2.3%	18,168	822,552	2.2%
Jun	19,523	810,240	2.4%	18,606	810,240	2.3%
Jul	25,533	833,568	3.1%	23,352	833,568	2.8%
Aug	18,211	838,248	2.2%	17,798	838,248	2.1%
Sep	21,017	810,048	2.6%	20,343	810,048	2.5%

Table 3-25 Units offered with lower minimum run time on price compared to cost but with positive markup in the Day-Ahead and Real-Time Energy Markets: January 1 through September 30, 2017

	Day-Ahead			Real-Time		
2017	Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost
Jan	12,346	803,424	1.5%	11,996	803,424	1.5%
Feb	10,356	729,264	1.4%	10,374	729,264	1.4%
Mar	6,831	806,810	0.8%	6,759	806,810	0.8%
Apr	5,757	792,480	0.7%	5,462	792,480	0.7%
May	5,904	822,552	0.7%	5,720	822,552	0.7%
Jun	8,750	810,240	1.1%	8,669	810,240	1.1%
Jul	7,162	833,568	0.9%	7,072	833,568	0.8%
Aug	7,128	838,248	0.9%	7,128	838,248	0.9%
Sep	6,480	810,048	0.8%	6,119	810,048	0.8%

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. A unit with a positive markup can have lower dispatch cost with price-based offer because of a lower economic minimum level compared to cost-based offer. Figure 3-26 shows an example of offers from a unit that has a positive markup and a price-based offer with a lower economic minimum MW than the cost-based offer. Keeping the startup cost, Minimum Run Time and No-load cost constant between the price-based offer and cost-based offer, the dispatch cost for this unit is lower on the price-based offer than on the cost-based offer. However, the price-based offer includes a positive markup and could result in setting the market price at a noncompetitive level even after the resource owner fails the TPS test.

Figure 3-26 Offers with a positive markup but different economic minimum MW

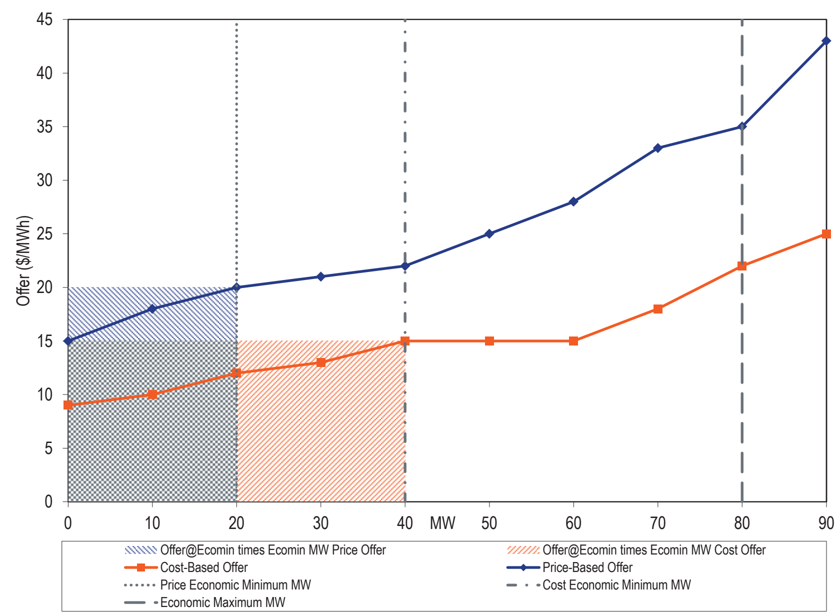


Table 3-26 shows the number and percent of unit schedule hours when units offered lower economic minimum MW in price-based offers than in cost-based offers while having a positive markup that resulted in the dispatch cost being lower for the price-based offer.

Table 3-26 Units offered with lower economic minimum MW on price compared to cost but with positive markup in the Day-Ahead and Real-Time Energy Markets: January 1 through September 30, 2017

	Day-Ahead			Real-Time		
2017	Number of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Number of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost
Jan	72	803,424	0.01%	48	803,424	0.01%
Feb	0	729,264	0.00%	0	729,264	0.00%
Mar	168	806,810	0.02%	136	806,810	0.02%
Apr	24	792,480	0.00%	0	792,480	0.00%
May	216	822,552	0.03%	216	822,552	0.03%
Jun	168	810,240	0.02%	168	810,240	0.02%
Jul	168	833,568	0.02%	152	833,568	0.02%
Aug	0	838,248	0.00%	0	838,248	0.00%
Sep	0	810,048	0.00%	0	810,048	0.00%

Table 3-27 Units with lower dispatch cost on price based offer compared to cost based offer, having positive markup in the Day-Ahead and Real-Time Energy Markets: January 1 through September 30, 2017

	Day-Ahead			Real-Time		
2017	Number of Schedule Hours with Potential Evasion	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Potential Evasion	Number of Schedule Hours with Potential Evasion	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Potential Evasion
Jan	30,582	803,424	3.8%	28,882	803,424	3.6%
Feb	28,426	729,264	3.9%	27,861	729,264	3.8%
Mar	27,298	806,810	3.4%	25,838	806,810	3.2%
Apr	23,050	792,480	2.9%	22,124	792,480	2.8%
May	22,757	822,552	2.8%	22,236	822,552	2.7%
Jun	26,414	810,240	3.3%	25,525	810,240	3.2%
Jul	31,365	833,568	3.8%	29,291	833,568	3.5%
Aug	23,891	838,248	2.9%	23,599	838,248	2.8%
Sep	25,769	810,048	3.2%	25,203	810,048	3.1%

Table 3-27 shows the number and percent of unit schedule hours that have exhibited one of the three behaviors (crossing curves, lower minimum run time on price based offer, lower economic minimum on price based offer) that resulted in the dispatch cost being lower for the price-based offer while having a positive markup. The data in Table 3-27 is a combination of the data for each individual behavior that is shown in Table 3-24, Table 3-25, and Table 3-26, adjusted for units that engaged in more than one such behavior simultaneously.

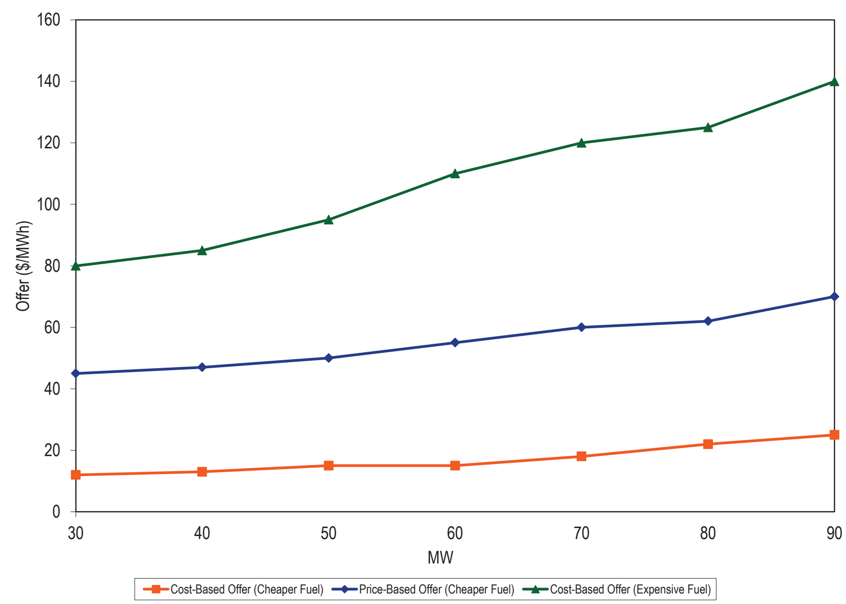
The MMU analyzed the data for units that exhibited any of the three behaviors (crossing curves, lower minimum run time on price based offer, lower economic minimum on price based offer) that also failed the TPS test in the Real-Time Energy Market, and were marginal in those intervals. Table 3-28 shows the total number of schedule hours when the units with behavior that resulted in evasion of market power mitigation rules failed the TPS test and were marginal in the Real-Time Energy Market.

Table 3-28 Units with potential evasion that failed the TPS test and were marginal in the Real-Time Energy Market: January 1 through September 30, 2017

2017	Schedule Hours with Potential Evasion When Units were Marginal	Number of Schedule Hours with Potential Evasion	Total Number of Cost Schedule Hours Offered by Price Based Units	Marginal Units with Evasion as a Percent of Total Schedule Hours	Marginal Units with Evasion as a Percent of Schedule Hours with Potential Evasion
Jan	848	28,882	803,424	0.1%	2.9%
Feb	894	27,861	729,264	0.1%	3.2%
Mar	1,495	25,838	806,810	0.2%	5.8%
Apr	814	22,124	792,480	0.1%	3.7%
May	505	22,236	822,552	0.1%	2.3%
Jun	327	25,525	810,240	0.0%	1.3%
Jul	623	29,291	833,568	0.1%	2.1%
Aug	389	23,599	838,248	0.0%	1.6%
Sep	1,739	25,203	810,048	0.2%	6.9%

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 3-27 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.

Figure 3-27 Dual fuel unit offers



These issues can be solved by simple rule changes.[45] The MMU recommends that markup of price based offers over cost-based offers be constant across the offer curve, that there be at least one cost-based offer using the same fuel as the available price-based offer, and that operating parameters on parameter limited schedules (PLS) be at least as flexible as price-based non-PLS offers.

Levels of offer capping have historically been low in PJM, as shown in Table 3-29. The offer capping percentages shown in Table 3-29 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.

Table 3-29 Offer capping statistics – energy only: January 1 through September 30, 2013 to 2017

	Real-Time		Day-Ahead	
(Jan-Sep)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
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%
2016	0.4%	0.2%	0.1%	0.0%
2017	0.3%	0.1%	0.0%	0.0%

Table 3-30 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 black start service and reactive support reasons increased from 2012 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 2014 because higher LMPs resulted in the increased economic dispatch of black start and reactive service resources. As of April 2015, the Automatic Load Rejection (ALR) units that were committed for black start previously no longer provide black start service, and are not included in the offer capping statistics for black start. PJM also created closed loop interfaces to, in some cases, model reactive constraints. The result was higher LMPs, which increased economic dispatch, which contributed to the reduction in units offer capped for reactive support. In instances where units are now committed for the modeled closed loop interface constraints, they are considered offer capped for providing constraint relief. They are included in the offer capping percentages in Table 3-29.

Table 3-30 Offer capping statistics for energy and reliability: January 1 through September 30, 2013 to 2017

	Real-Time		Day-Ahead	
(Jan-Sep)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
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%
2016	0.4%	0.2%	0.1%	0.1%
2017	0.4%	0.4%	0.1%	0.3%

Table 3-31 shows the offer capping percentages for units committed to provide black start service and reactive support. The data in Table 3-31 is the difference between the offer cap percentages shown in Table 3-30 and Table 3-29.

Table 3-31 Offer capping statistics for reliability: January 1 through September 30, 2013 to 2017

	Real-Time		Day-Ahead	
(Jan-Sep)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
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%
2016	0.0%	0.0%	0.0%	0.0%
2017	0.1%	0.3%	0.1%	0.3%

45 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) and subsequently in the MMU's protest in the hourly offers proceeding in Docket No. ER16-372-000, filed December 14, 2015.

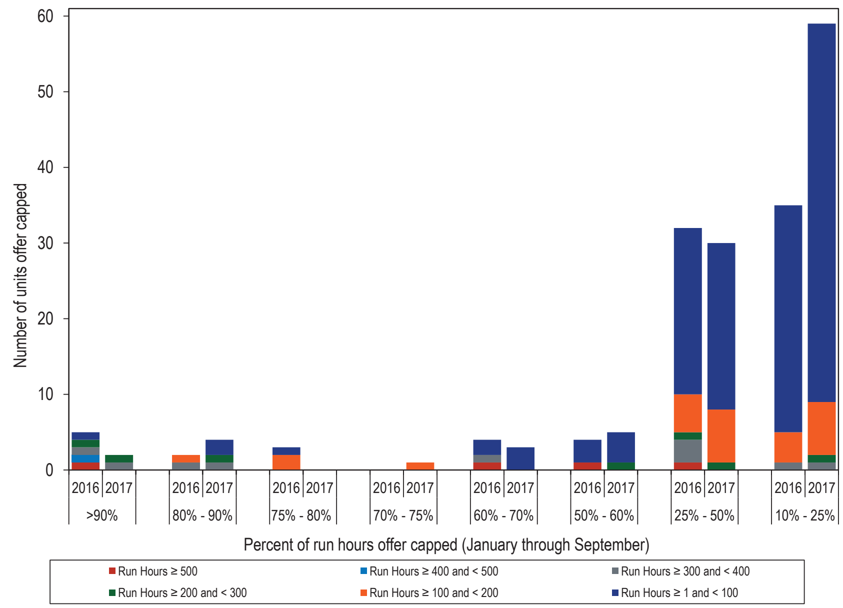
Table 3-32 presents data on the frequency with which units were offer capped in the first nine months of 2016 and 2017 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market. Table 3-32 shows that two units were offer capped for 90 percent or more of their run hours in the first nine months of 2017 compared to five in the first nine months of 2016.

Table 3-32 Real-time offer capped unit statistics: January 1 through September 30, 2016 and 2017

		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%	2016	1	1	1	1	0	1
	2017	0	0	1	1	0	0
80% and < 90%	2016	0	0	1	0	1	0
	2017	0	0	1	1	0	2
75% and < 80%	2016	0	0	0	0	2	1
	2017	0	0	0	0	0	0
70% and < 75%	2016	0	0	0	0	0	0
	2017	0	0	0	0	1	0
60% and < 70%	2016	1	0	1	0	0	2
	2017	0	0	0	0	0	3
50% and < 60%	2016	1	0	0	0	0	3
	2017	0	0	0	1	0	4
25% and < 50%	2016	1	0	3	1	5	22
	2017	0	0	0	1	7	22
10% and < 25%	2016	0	0	1	0	4	30
	2017	0	0	1	1	7	50

Figure 3-28 shows the frequency with which units were offer capped in the first nine months of 2016 and 2017 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market.

Figure 3-28 Real-time offer capped unit statistics: January 1 through September 30, 2016 and 2017



TPS Test Statistics

In the first nine months of 2017, the AEP, APS, ATSI, BGE, ComEd, Dominion, DPL, JCPL, PECO, PENELEC, and PPL control zones experienced congestion resulting from one or more constraints binding for 75 or more hours or resulting from an interface constraint (Table 3-33). The AECO, DAY, DEOK, DLCO, EKPC, Met-Ed, Pepco, PSEG, and RECO control zones did not have constraints binding for 75 or more hours in the first nine months of 2017. Table 3-33 shows that AEP, BGE, ComEd, Dominion and PPL were the control zones that 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 the first nine months of every year from 2009 through 2017. The constrained hours in the BGE Zone decreased from 8,506 hours in the first nine months of 2016 to 1,748 hours in the first nine months of 2017 due to the completion of RTEP upgrades in the zone. The constrained hours in the ComEd Zone decreased from 4,754 hours in the first nine months of 2016 to 1,401 hours in the first nine months of 2017 due to the completion of equipment outages.

Table 3-33 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 1 through September 30, 2009 through 2017

	(Jan - Sep)								
	2009	2010	2011	2012	2013	2014	2015	2016	2017
AECO	149	163	234	0	0	0	192	413	0
AEP	1,005	1,265	2,452	178	2,018	1,821	1,891	633	469
APS	421	1,121	87	89	0	170	451	157	136
ATSI	140	0	0	208	68	481	424	1	427
BGE	127	274	368	1,582	1,192	4,416	6,006	8,506	1,748
ComEd	784	2,108	1,118	1,808	3,169	1,928	1,708	4,754	1,401
DEOK	0	0	0	185	0	0	0	0	0
DLCO	156	393	0	209	0	223	617	0	0
Dominion	456	889	1,266	559	674	77	1,341	647	80
DPL	0	111	0	382	783	542	1,138	2,691	326
JCPL	0	0	0	0	0	0	79	170	253
Met-Ed	0	168	0	0	0	0	222	0	0
PECO	247	0	276	0	390	1,826	718	826	975
PENELEC	80	96	77	0	0	2,147	1,287	451	1,992
Pepco	149	0	76	143	200	41	0	0	0
PPL	176	117	40	146	609	148	224	398	1,370
PSEG	379	515	1,132	259	1,993	2,268	2,509	0	0

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 2017.[46] 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.

46 See the *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

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

Table 3-34 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 3-34 Three pivotal supplier test details for interface constraints: January 1 through September 30, 2017

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AEP - DOM	Peak	197	106	11	0	11
	Off Peak	225	173	7	0	7
AP South	Peak	448	656	15	2	13
	Off Peak	426	645	11	0	10
Bedington - Black Oak	Peak	118	191	12	4	7
	Off Peak	100	100	8	1	7
Seneca	Peak	125	132	1	0	1
	Off Peak	139	151	1	0	1

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. Steam units that are offer capped in the Day-Ahead Energy Market continue to be offer capped in the Real-Time Energy Market regardless of their inclusion in the TPS test in real time and the outcome of the TPS test in real time. 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 3-35 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. The three pivotal supplier tests that resulted in offer capping do not explain all the offer capped units in the Real-Time Energy Market. PJM operators also manually commit units for reliability reasons that are not specifically for providing relief to a binding constraint.

Table 3-35 Summary of three pivotal supplier tests applied for interface constraints: January 1 through September 30, 2017

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
AEP - DOM	Peak	2	2	100%	0	0%	0%
	Off Peak	95	53	56%	7	7%	13%
AP South	Peak	201	123	61%	10	5%	8%
	Off Peak	390	184	47%	9	2%	5%
Bedington - Black Oak	Peak	50	36	72%	2	4%	6%
	Off Peak	151	98	65%	7	5%	7%
Seneca	Peak	366	2	1%	0	0%	0%
	Off Peak	582	0	0%	0	0%	NA

Parameter Limited Schedules

Cost-Based Offers

All capacity resources in PJM are required to submit at least one cost-based offer. During the 2016/2017 and 2017/2018 delivery years, all cost-based offers, submitted by resources that are not capacity performance resources, are parameter limited in accordance with the Parameter Limited Schedule (PLS) matrix or with the level of an approved exception.[47] During the 2016/2017 and 2017/2018 delivery years, all cost-based offers, submitted by capacity performance resources, are parameter limited in accordance with predetermined unit specific parameter limits. During the 2016/2017 and 2017/2018 delivery years, there was no base capacity procured.

For the 2018/2019 and 2019/2020 delivery years, PJM procured two types of capacity resources, capacity performance resources and base capacity resources. Beginning June 1, 2018, there will no longer be any resources committed as the current annual capacity product. All cost-based offers, submitted by capacity performance resources and base capacity resources, are parameter limited in accordance with predetermined unit specific parameter limits.

Price-Based Offers

All capacity resources that choose to offer price-based offers are required to make available at least one price-based parameter limited offer (referred to as price-based PLS). For resources that are not capacity performance resources or not base capacity resources, the price-based parameter limited schedule is to be used by PJM for committing generation resources when a maximum emergency generation alert is declared. For capacity performance resources, the price-based parameter limited schedule is to be used by PJM for committing generation resources when hot weather alerts and cold weather alerts are declared. For base capacity resources (during the 2018/2019 and 2019/2020 delivery years only), the price-based parameter limited schedule is to be used by PJM for committing generation resources when hot weather alerts are declared.

Parameter Limits

During the extreme cold weather conditions in the first three months of 2016, as well as 2015 and 2014, 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, the ratio of economic maximum MW to economic

47 See PJM OATT Attachment K Appendix § 6.6 (Minimum Generator Operating Parameters—Parameter-Limited Schedules) (June 1, 2017) at 2367 - 2376.

minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may, depending on the nature of the transportation service purchased, 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 1.0, to avoid deviations from the hourly nominated quantity.

Key parameters like startup and notification time were not included in the PLS matrix in 2016 and prior periods for annual resources that do not have capacity performance obligations. 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. Startup and notification times are limited for capacity performance resources beginning June 1, 2016, in accordance with predetermined unit specific parameter limits. The unit specific parameter limits for capacity performance resources were based on default minimum operating parameter limits posted by PJM by technology type. These default parameters were based on analysis by the MMU. Market participants could request an adjustment to the default values by submitting supporting documentation, which was reviewed by PJM and the MMU. The default minimum operating parameter limits or approved adjusted values are used by capacity performance resources for their parameter limited schedules.

PJM has the authority to approve adjusted parameters with input from the MMU. PJM has inappropriately applied different review standards to coal units than to CTs and CCs despite the objections of the MMU. PJM has approved parameter limits for steam units based on historical performance and existing equipment while holding CTs and CCs to higher standards based on OEM documentation and up to date equipment configuration.

Currently, there are no rules in the PJM tariff or manuals that limit the nonparameter attributes of price-based PLS offers. The intent of the price-based PLS offer is to prevent the exercise of market power during high demand conditions by preventing units from offering inflexible operating parameters in order to extract higher market revenues or higher uplift payments. However, a generator can include a higher markup in the price-based PLS offer than in the price-based non-PLS schedule. The result is that the offer is higher and market prices are higher as a result of the exercise of market power using the PLS offer. This defeats the purpose of requiring price-based PLS offers.

The MMU recommends that in order to ensure rigorous market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available non-PLS price-based offer, and that the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer.

Parameter Limited Schedules under Capacity Performance

Beginning in the 2016/2017 delivery year, 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. For the 2018/2019 and 2019/2020 delivery years, resources that have base capacity commitments are also required to submit, in their parameter limited schedules, unit specific parameters that reflect the physical capability of the technology type of the resource. In its order on capacity performance, the Commission determined that capacity performance 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.[48] The Commission directed that capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.[49] The Commission directed PJM to submit tariff language to establish a process through which capacity performance resources that operate outside the defined unit-specific parameter limits can justify such operation and therefore remain eligible for make whole payments.[50]

48 151 FERC ¶ 61,208 at P 437 (June 9th Order).
49 *Id* at P 439.
50 *Id* at P 440.

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 June 9th Order's determination on parameters is not consistent with that goal. By permitting generation owners to establish unit parameters based on nonphysical 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 or that such a contract can reasonably impose costs on customers who were not party to the contract. 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 will increase energy market uplift payments substantially. Uplift costs are unpredictable, opaque and unhedgeable. While some uplift is necessary and efficient in an LMP market, this uplift is not. 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 MMU recommends 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 and the assignment of performance risk to generation owners.

The MMU recommends that capacity performance resources and base capacity resources (during the June through September period) be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. This solution creates the incentives for flexibility and preserves, to the extent possible, the incentives to follow PJM's dispatch instructions during high demand conditions. The proposed operating parameters should be based on the physical capability of the Reference Resource used in the Cost of New Entry, currently two GE Frame 7FA turbines with dual fuel capability. All resources that are less flexible than the Reference Resource are expected to be scheduled and running during high demand conditions anyway, while the flexible CTs that are used as peaking plants would still have the incentive to follow LMP and dispatch instructions. CCs would also have the capability to be as flexible as the reference resource. These units will be exempt from nonperformance charges and made whole as long as they perform in accordance with their parameters. This ensures that all the peaking units that are needed by PJM for flexible operation do not self schedule at their maximum output, and follow PJM dispatch instructions during high demand conditions. If any of the less flexible resources need to be dispatched down by PJM for reliability reasons, they would be exempt from nonperformance charges.

Such an approach is consistent with the Commission's no excuses policy for nonperformance because the flexibility target is set based on the optimal OEM-defined capability for the marginal resource that is expected to meet peak demand, which is consistent with the level of performance that customers are paying for in the capacity market. Any resource that is less flexible is not excused for nonperformance and any resource that meets the flexibility target is performing according to the commitments made in the capacity market.

The June 9th Order pointed out that the way to ensure that a resource's parameters are exposed to market consequences is to not allow any parameter limitations as an excuse for nonperformance. The same logic should apply to energy market uplift rules. A resource's parameters should be exposed to market consequences and the resource should not be made whole if it is operating less flexibly than the reference resource. 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.

Markup Index

Markup is a summary measure of participant offer behavior or conduct for individual units. When a seller responds competitively to a market price, markup is zero. When a seller exercises market power in its pricing, markup is positive. The degree of markup increases with the degree of market power. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[51] The markup index is normalized and can vary from -1.00 when the offer price is less than short run marginal cost, to 1.00 when the offer price is higher than short run marginal cost. The markup index does not measure the impact of unit markup on total LMP. The dollar markup for a unit is the difference between price and cost.

Real-Time Markup

Table 3-36 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using unadjusted cost offers. Table 3-37 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using adjusted cost offers. The unadjusted markup is the difference between the price offer and the cost offer including the 10 percent adder in the cost offer. The adjusted markup is the difference between the price offer and the cost offer excluding the 10 percent adder from the cost offer. The adjusted markup is calculated for coal, gas and oil units because these units have consistently had price-based offers less than cost-based offers.[52] The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point.

All generating units are allowed to add an additional 10 percent to their cost offer. The additional 10 percent 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. The owners of coal units, facing competition, typically exclude the additional 10 percent from their actual offers. The owners of gas fired and oil fired units have also begun to exclude the 10 percent adder. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the additional 10 percent in the cost offer for coal gas and oil fired units. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the additional 10 percent from the cost offers of coal gas and oil fired units. Even the adjusted markup overestimates the negative markup because units facing increased competitive pressure have excluded both the 10 percent and the components of operating and maintenance cost that are not short run marginal cost. While the10 percent adder is permitted under the definition of cost-based offers in the PJM Market Rules and some have interpreted the rules to permit maintenance costs that are not short run marginal costs, neither are part of a competitive offer because they are not actually short run marginal costs, and actual market behavior reflects that fact.[53]

In the first nine months of 2017, 93.0 percent of marginal units had offer prices less than $50 per MWh. The average dollar markups of units with offer prices less than $25 was positive ($0.21 per MWh) when using unadjusted cost offers. The average dollar markups of units with offer prices between $25 and $50 was positive ($1.67 per MWh) when using unadjusted cost offers.

51 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00) for comparison across both low and high cost units, the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

52 The MMU will calculate adjusted markup for gas units also in future reports because gas units also more consistently have price-based offers less than cost-based offers.

53 See PJM. "Manual 15: Cost Development Guidelines," Revision 29 (May 15, 2017).

Negative markup means the unit is offering to run at a price less than its cost-based offer, revealing a short run marginal cost that is less than the maximum allowable cost-based offer under the PJM Market Rules.

Some marginal units did have substantial markups. Among the units that were marginal in the first nine months of 2017, none had offer prices above $400 per MWh. Among the units that were marginal in the first nine months of 2016, less than 0.1 percent had offer prices greater than $400 per MWh. Using the unadjusted cost offers, the highest markup for any marginal unit in the first nine months of 2017 was $755.09 while the highest markup in the first nine months of 2016 was $258.16.

Table 3-36 Average, real-time marginal unit markup index (By offer price category unadjusted): January 1 through September 30, 2016 and 2017

	2016 (Jan-Sep)			2017 (Jan-Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.01	($0.92)	62.6%	0.17	$0.21	65.2%
$25 to $50	(0.03)	($2.08)	25.7%	0.06	$1.67	27.8%
$50 to $75	0.18	$10.11	1.6%	0.38	$22.33	1.8%
$75 to $100	0.31	$26.46	0.5%	0.28	$24.21	0.7%
$100 to $125	0.05	$5.04	2.4%	0.37	$40.82	0.2%
$125 to $150	0.01	$1.43	5.2%	0.25	$32.45	0.3%
>= $150	0.04	$7.31	2.0%	0.01	$1.40	4.0%

Table 3-37 Average, real-time marginal unit markup index (By offer price category adjusted): January 1 through September 30, 2016 and 2017

	2016 (Jan-Sep)			2017 (Jan-Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.09	$0.78	62.6%	0.25	$1.75	65.2%
$25 to $50	0.06	$0.98	25.7%	0.15	$4.34	27.8%
$50 to $75	0.25	$14.35	1.6%	0.44	$25.42	1.8%
$75 to $100	0.37	$32.06	0.5%	0.35	$30.06	0.7%
$100 to $125	0.14	$14.59	2.4%	0.43	$47.22	0.2%
$125 to $150	0.11	$13.80	5.2%	0.32	$41.91	0.3%
>= $150	0.13	$22.59	2.0%	0.10	$20.27	4.0%

Table 3-38 shows the percentage of marginal units that had markups, calculated using unadjusted cost offers, below, above and equal to zero for coal, gas and oil fuel types.[54] Table 3-39 shows the percentage of marginal units that had markups, calculated using adjusted cost offers, below, above and equal to zero for coal, gas and oil fuel types. In the first nine months of 2017, using unadjusted cost-based offers for coal units, 45.78 percent of coal units had negative markups. In the first nine months of 2017, using adjusted cost-based offers for coal units, 25.06 percent of coal units had negative markups.

Table 3-38 Percent of marginal units with markup below, above and equal to zero (By fuel type unadjusted): January 1 through September 30, 2016 and 2017

	2016 (Jan-Sep)			2017 (Jan-Sep)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	62.77%	19.54%	17.69%	45.78%	21.65%	32.57%
Gas	22.17%	16.19%	61.64%	37.18%	13.22%	49.60%
Oil	11.04%	85.20%	3.75%	38.90%	60.17%	0.94%

Table 3-39 Percent of marginal units with markup below, above and equal to zero (By fuel type adjusted): January 1 through September 30, 2016 and 2017

	2016 (Jan-Sep)			2017 (Jan-Sep)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	44.62%	2.83%	52.55%	24.76%	5.47%	69.77%
Gas	5.40%	2.64%	91.96%	9.72%	5.88%	84.40%
Oil	0.02%	0.00%	99.98%	0.07%	0.00%	99.93%

Figure 3-29 shows the frequency distribution of hourly markups for all gas units offered in the first nine months of 2016 and 2017 using unadjusted cost offers. The highest markup within the economic operating range of the unit's offer curve was used for creating the frequency distributions.[55] Of the gas units offered in the PJM market in the first nine months of 2017, nearly 28 percent of gas unit-hours had a maximum markup that was negative. More than 6.5 percent of gas fired unit-hours had a maximum markup above $100 per MWh.

54 Other fuel types were excluded based on data confidentiality rules.
55 The categories in the frequency distribution were chosen so as to maintain data confidentiality.

Figure 3-29 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: January 1 through September 30, 2016 and 2017

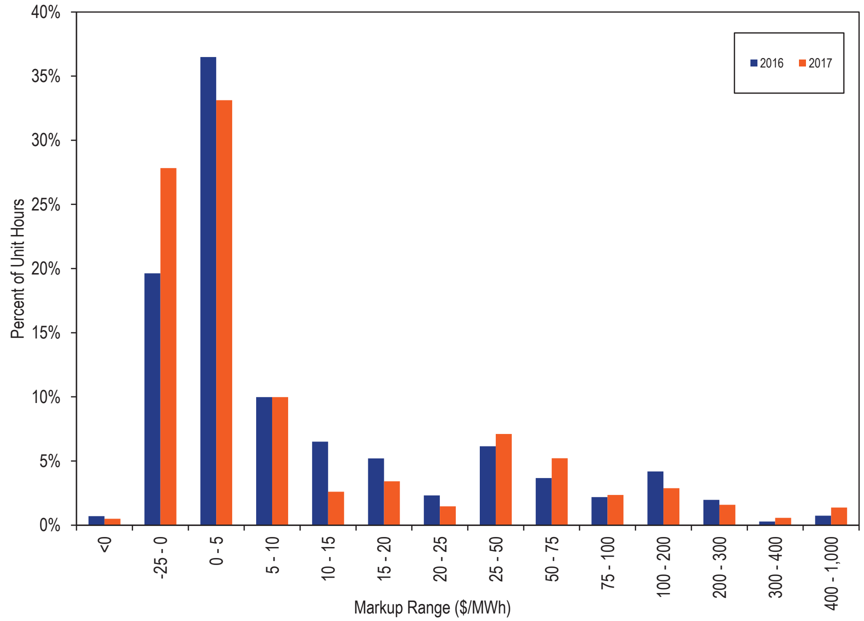


Figure 3-30 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: January 1 through September 30, 2016 and 2017

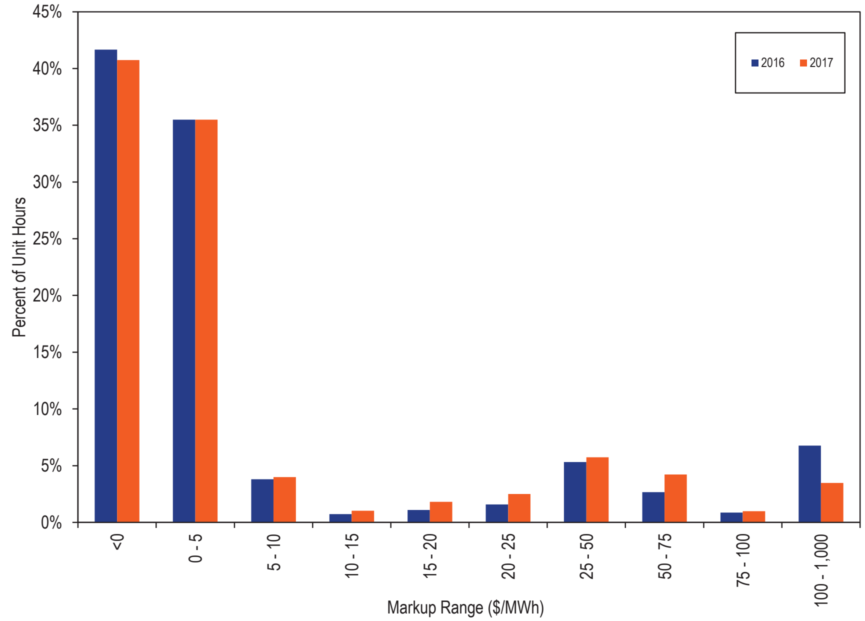
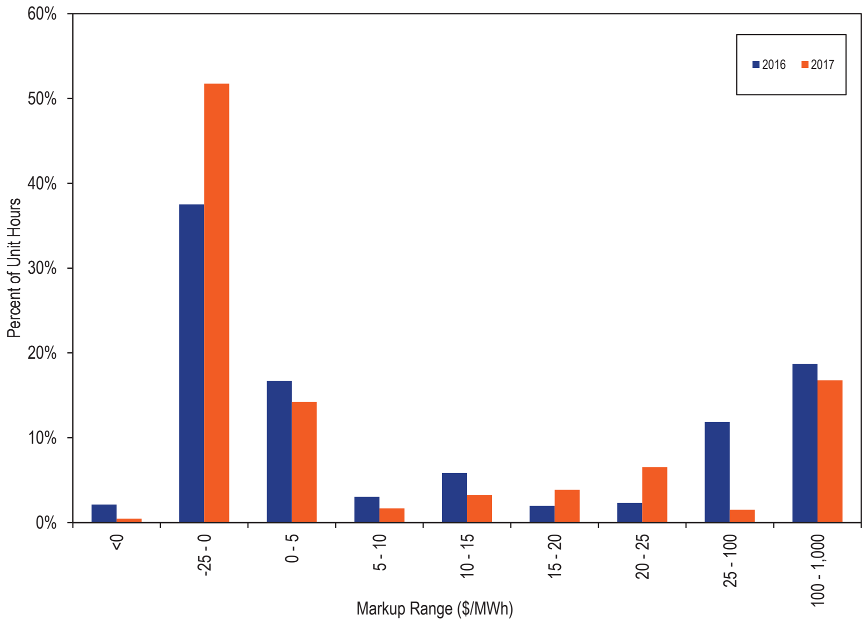


Figure 3-30 shows the frequency distribution of hourly markups for all coal units offered in the first nine months of 2016 and 2017 using unadjusted cost offers. Of the coal units offered in the PJM market in the first nine months of 2017, nearly 41 percent of coal unit-hours had a maximum markup that was negative.

Figure 3-31 shows the frequency distribution of hourly markups for all offered oil units in the first nine month of 2016 and 2017 using unadjusted cost offers. Of the oil units offered in the PJM market in the first nine months of 2017, nearly 52 percent of oil unit-hours had a maximum markup that was negative.

Figure 3-31 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: January 1 through September 30, 2016 and 2017

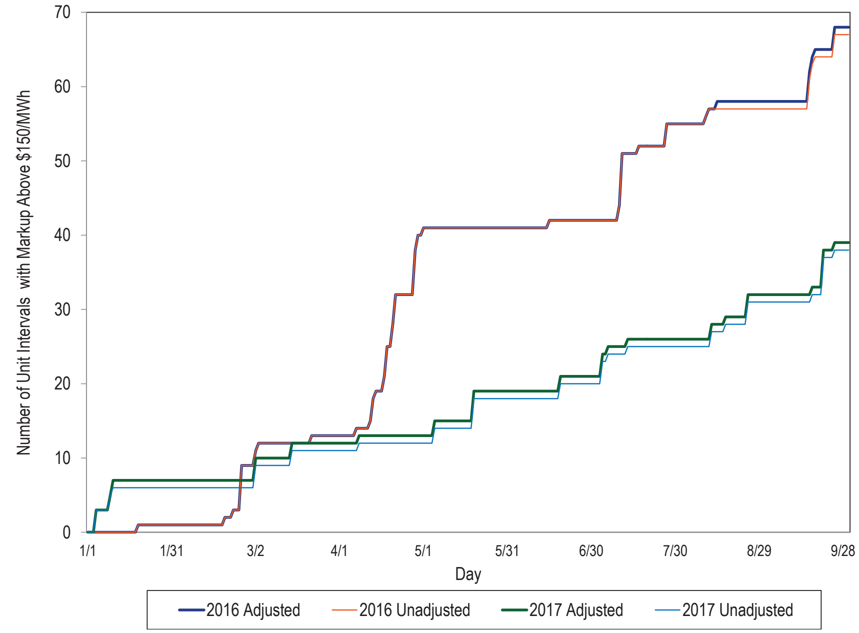


The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power.

Figure 3-32 show the number of marginal unit intervals in the first nine months of 2017 and 2016 with markup above $150 per MWh.

Figure 3-32 Cumulative number of unit intervals with markups above $150 per MWh: January 1 through September 30, 2016 and 2017



Day-Ahead Markup

Table 3-40 shows the average markup index of marginal generating units in the Day-Ahead Energy Market, by offer price category using unadjusted offers. The majority of marginal units are virtual transactions, which do not have markup. In the first nine months of 2017, 94.3 percent of marginal generating units had offer prices less than $50 per MWh. The average dollar markups of units with offer prices less than $25 was positive ($0.23 per MWh) when using unadjusted cost offers. The average dollar markups of units with offer prices between $25 and $50 was positive ($3.23 per MWh) when using unadjusted cost offers.

Some marginal units did have substantial markups. Among the units that were marginal in the first nine months of 2017, none had offer prices above $400 per MWh. Among the units that were marginal in the first nine months of 2016, none had offer prices greater than $400 per MWh. Using the unadjusted cost offers, the highest markup for any marginal unit in the first nine months of 2017 was $47.74 while the highest markup in the first nine months of 2016 was $170.99.

Table 3-40 Average day-ahead marginal unit markup index (By offer price category, unadjusted): January 1 through September 30, 2016 and 2017

	2016 (Jan - Sep)			2017 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.10	($0.15)	60.8%	0.17	$0.23	61.5%
$25 to $50	0.03	$0.01	26.6%	0.10	$3.23	32.8%
$50 to $75	0.09	$5.42	1.6%	0.21	$11.82	0.7%
$75 to $100	0.03	$2.04	0.1%	0.02	$1.43	0.4%
$100 to $125	(0.01)	($0.72)	0.4%	0.00	$0.00	0.0%
$125 to $150	0.00	$0.00	9.1%	0.00	$0.00	0.0%
>= $150	0.01	$2.66	1.3%	(0.01)	($1.56)	4.6%

Table 3-41 shows the average markup index of marginal generating units in the Day-Ahead Energy Market, by offer price category using adjusted offers. In the first nine months of 2017, 0.4 percent of marginal generating units had offers between $75 and $100 per MWh and the average dollar markup and the average markup index were both positive. The average markup index increased from 0.17 in the first nine months of 2016, to 0.25 in the first nine months of 2017 in the offer price category less than $25.

Table 3-41 Average day-ahead marginal unit markup index (By offer price category, adjusted): January 1 through September 30, 2016 and 2017

	2016 (Jan - Sep)			2017 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.17	$1.57	60.8%	0.25	$1.90	61.5%
$25 to $50	0.11	$2.88	26.6%	0.18	$5.68	32.8%
$50 to $75	0.17	$9.97	1.6%	0.28	$15.65	0.7%
$75 to $100	0.12	$9.60	0.1%	0.11	$9.80	0.4%
$100 to $125	0.08	$9.76	0.4%	0.00	$0.00	0.0%
$125 to $150	0.09	$12.44	9.1%	0.09	$11.86	0.0%
>= $150	0.10	$19.46	1.3%	0.09	$16.75	4.6%

Energy Market Cost-Based Offers

The application of market power mitigation rules in the Day-Ahead Energy Market and the Real-Time Energy Market helps ensure competitive market outcomes even in the presence of structural market power. But the efficacy of market power mitigation rules depends on the definition of a competitive offer. A competitive offer is equal to short run marginal costs. The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, as interpreted by PJM, is not currently correct. Some unit owners include costs that are not short run marginal costs in offers, including maintenance costs. This issue can be resolved by simple changes to the PJM market rules to incorporate a clear and accurate definition of short run marginal costs.

Short Run Marginal Costs

There are three types of costs identified under PJM rules:

- Short run marginal costs (or incremental costs). Short run costs incurred directly as a result of producing energy for an hour;
- Avoidable costs. Annual costs that would be avoided if energy were not produced over an annual period;
- Fixed costs. Costs associated with an investment in a facility including the return on and of capital.

Marginal costs are the only costs relevant to the energy market. Specifically, the competitive energy offer level is the short run marginal cost of production.

The MMU recommends that PJM require that the level of incremental costs includable in cost-based offers not exceed the unit's short run marginal cost.

Fuel Cost Policies

The fuel cost policy documents the process by which the Market Seller calculates the fuel cost component of its cost-based offers. Short run marginal fuel costs include commodity costs, transportation costs, fees, and taxes for the purchase of fuel. Fuel handling costs and fuel additive costs are included in the cost-based offer as variable operations and maintenance (VOM) costs. The fuel cost policy documents the frequency with which the Market Seller updates VOM and other nonfuel cost inputs.

The verification of accurate fuel costs in cost-based offers is not possible unless the fuel cost policy is algorithmic, verifiable, and systematic. Algorithmic means that the fuel cost policy must use a set of defined, logical steps to use defined inputs to get to defined outputs. Verifiable means that the fuel cost policy must provide a fuel price that can be calculated by the MMU after the fact with the same data available to the generation owner at the time the decision was made, and documentation for that data from a public or a private source. Systematic means that the fuel cost policy must document a standardized method or methods for calculating fuel costs including objective triggers for each method.

The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic.

Cost Development Guidelines

The Cost Development Guidelines contained in PJM Manual 15 do not clearly or accurately describe the short run marginal cost of generation. The MMU recommends that Manual 15 be replaced with a straightforward description of the components of cost offers based on short run marginal costs and the correct calculation of cost offers.

FERC System of Accounts

PJM Manual 15 relies heavily on the FERC System of Accounts, which predates markets and does not define costs consistently with market economics.

The MMU recommends removal of all use of the FERC System of Accounts in the Cost Development Guidelines.

Cyclic Starting and Peaking Factors

The use of cyclic starting and peaking factors for calculating VOM costs for combined cycles and combustion turbines is designed to allocate a greater proportion of long term maintenance costs to starts and the tail block of the cost curve. The use of such factors is not appropriate given that long term maintenance costs are not short run marginal costs and should not be included in cost offers.

The MMU recommends the removal of all cyclic starting and peaking factors from the Cost Development Guidelines.

Labor Costs

PJM Manual 15 allows for the inclusion of plant staffing costs in energy market cost offers. This is inappropriate given that labor costs are avoidable costs, not short run marginal costs, and are correctly includable in the RPM Avoidable Cost Rate.

The MMU recommends the removal of all labor costs from the Cost Development Guidelines.

Combined Cycle Start Heat Input Definition

PJM Manual 15 defines the start heat input of combined cycles as the amount of fuel used from the firing of the first combustion turbine to the close of the steam turbine breaker plus any fuel used by other combustion turbines in the combined cycle from firing to the point at which the HRSG steam pressure matches the steam turbine steam pressure. This definition is inappropriate given that after each combustion turbine is synchronized, some of the fuel is used to produce energy for which the resource is compensated in the energy market.

The MMU recommends changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. This change will make the treatment of combined cycles consistent with steam turbines.

Nuclear Costs

The fuel costs for nuclear plants are fixed in the short run and amortized over the period between refueling outages. The short run marginal cost of fuel for nuclear plants is zero. Operations and maintenance costs for nuclear power plants consist primarily of labor and maintenance costs incurred during outages, which are also fixed in the short run.

The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines.

Pumped Hydro Costs

The calculation of pumped hydro costs for energy storage in Section 7.3 of PJM Manual 15 is inaccurate. The mathematical formulation contains an error in the calculation of the weighted average pumping cost, and it does not take into account the purchase of power for pumping in the day-ahead market.

The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases.

Energy Market Opportunity Costs

The calculation of energy market opportunity costs for energy limited units in Section 12 of PJM Manual 15 fails to account for a number of physical unit characteristics and environmental restrictions that influence opportunity costs. These include start up time, notification time, minimum down time, multiple fuel capability, multiple emissions limitations, and fuel usage limitations.

The MMU recommends revisions to the calculation of energy market opportunity costs to incorporate all time based offer parameters and all limitations that affect the opportunity cost of generating unit output.

The use of Catastrophic Force Majeure as the criterion for the use of opportunity costs for fuel supply limitations in Schedule 2 of the Operating Agreement is overly restrictive. This criterion would not allow the use of opportunity costs to allocate limited fuel in the case of regional fuel transportation disruptions or extreme weather events.

The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2.

Frequently Mitigated Units (FMU) and Associated Units (AU)

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.[56] 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, and changes to the scarcity pricing rules in 2012. 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.

For those reasons, the MMU recommended the elimination of FMU and AU adders.[57] 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 generating units to qualify for FMU adders when units have net revenues less than unit going forward costs or ACR. PJM submitted the joint MMU/PJM proposal to the Commission pursuant to

56 110 FERC ¶ 61,053 (2005).
57 See the "*FMU Problem Statement and Issue Charge*," MIC <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_MIC_FMU_Problem_Statement_and_Issue_Charge_20130306.pdf>.

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.

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 eligible for 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 eligible for 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 eligible for 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.

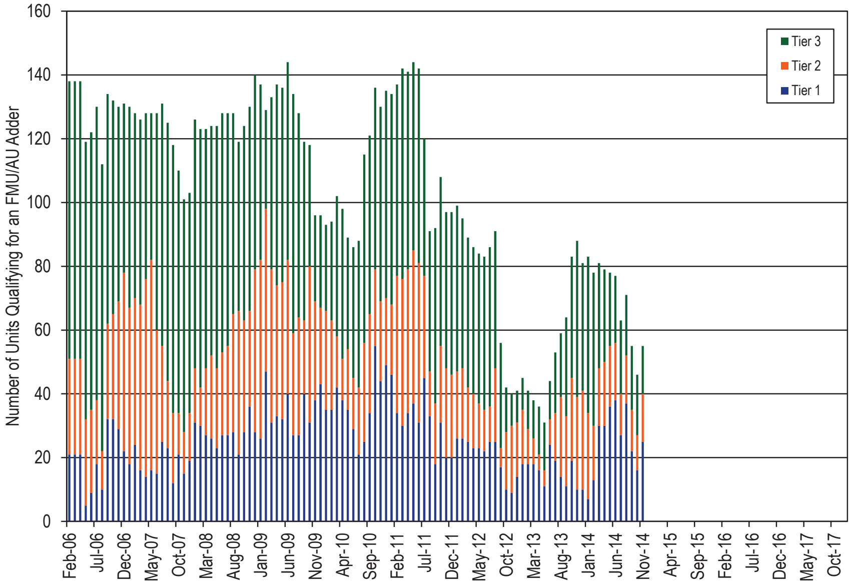
In addition to being offer capped for the designated percent of run hours, in order to qualify for an FMU adder, a generating unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis, divided by the unit's MW of installed capacity (in $/MW-year) must 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 an 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.[58]

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.[59] 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.

Figure 3-33 shows the total number of FMUs and AUs that qualified for an adder since the inception of the business rule in February 2006. The new rules for determining the qualification of a unit as an 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.[60] 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 since December 2014.

58 OA, Schedule 1 § 6.4.2.
59 An associated unit (AU) must belong to the same design class (where a design class includes generation that is the same size and uses the same technology, without regard to manufacturer) and uses the identical primary fuel as the FMU.
60 OA, Schedule 1 § 6.4.2. In 2007, the FERC approved OA revisions to clarify the AU criteria.

Figure 3-33 Frequently mitigated units and associated units (By month): February 1, 2006 through September 30, 2017



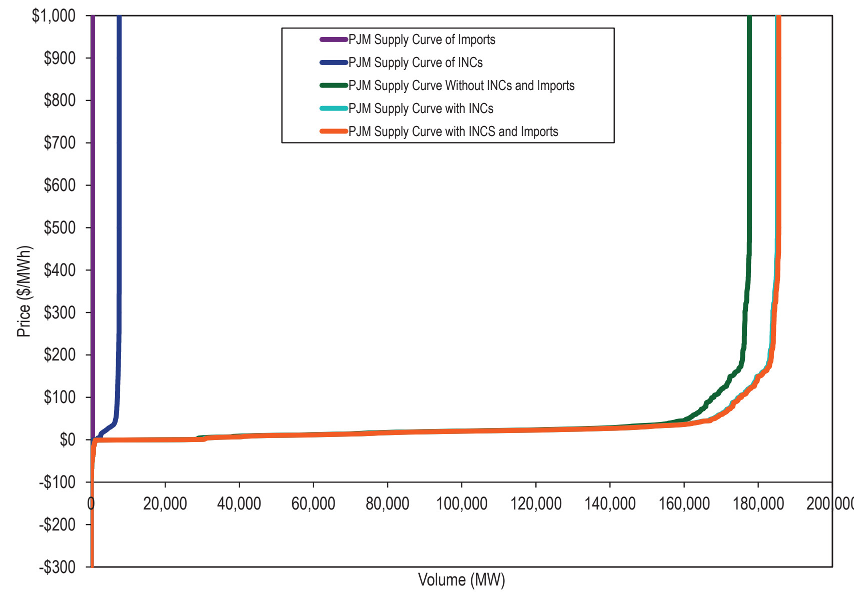
Virtual Offers and Bids

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 market clearing 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 431 buses, eligible for up to congestion transaction bidding.[61] Financial Transaction Rights (FTRs) bids may be submitted at any bus on a list of selected buses that change every planning period, 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 3-34 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 2017.

Figure 3-34 PJM day-ahead aggregate supply curves: 2017 example day



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

Table 3-42 shows the hourly average number of cleared and submitted increment offers and decrement bids by month in 2016 and the first nine months of 2017. The hourly average submitted and cleared increment MW increased by 21.4 and 6.5 percent, from 7,017 MW and 4,577 MW in the first nine months of 2016 to 8,521 MW and 4,876 MW in the first nine months of 2017. The hourly average submitted and cleared decrement MW increased by 20.7 percent and 7.6 percent, from 6,918 MW and 4,087 MW in the first nine months of 2016 to 8,349 MW and 4,397 MW in the first nine months of 2017.

Table 3-42 Hourly average number of cleared and submitted INCs, DECs by month: January 1, 2016 through September 30, 2017

		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
2016	Jan	4,350	6,447	78	398	5,153	7,320	76	295
2016	Feb	4,754	7,109	116	578	4,511	7,445	72	409
2016	Mar	4,973	8,689	142	760	4,305	8,894	101	648
2016	Apr	4,511	6,351	187	558	3,453	6,990	84	451
2016	May	5,089	7,459	181	656	4,171	6,823	94	404
2016	Jun	4,592	7,043	143	697	4,196	6,696	89	410
2016	Jul	4,101	6,534	128	745	3,335	5,830	86	448
2016	Aug	4,457	6,956	135	749	3,433	5,506	74	398
2016	Sep	4,527	6,772	148	733	4,391	7,030	112	437
2016	Oct	4,631	7,112	199	846	3,990	6,757	112	462
2016	Nov	5,022	7,822	223	1,008	3,671	6,435	109	482
2016	Dec	5,102	7,775	189	1,010	4,028	6,869	129	486
2016	Annual	4,675	7,175	156	729	4,051	6,879	95	444
2017	Jan	5,855	10,169	205	1,288	4,811	9,753	136	821
2017	Feb	6,058	10,590	266	1,430	4,599	9,326	149	784
2017	Mar	6,427	10,516	312	1,669	5,170	9,915	170	1,019
2017	Apr	5,115	8,860	280	1,401	5,139	8,986	178	776
2017	May	5,643	9,724	278	1,286	5,030	9,188	164	768
2017	Jun	3,961	7,705	193	1,153	4,314	8,257	173	831
2017	Jul	3,921	7,087	233	1,014	3,807	7,828	167	779
2017	Aug	3,418	5,951	279	1,022	3,209	5,845	169	593
2017	Sep	3,537	6,201	190	919	3,502	6,076	139	603
2017	Annual	4,876	8,521	248	1,241	4,397	8,349	161	775

Table 3-43 shows the average hourly number of up to congestion transactions and the average hourly MW in 2016 and the first nine months of 2017. In the first nine months of 2017, the average hourly up to congestion submitted MW increased 1.1 percent and cleared MW increased 6.6 percent, compared to the first nine months of 2016.

Table 3-43 Hourly average of cleared and submitted up to congestion bids by month: January 1, 2016 through September 30, 2017

		Up to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2016	Jan	39,639	135,369	2,466	6,015
2016	Feb	38,814	152,891	2,091	5,748
2016	Mar	31,817	148,162	1,703	5,101
2016	Apr	29,212	128,349	2,689	6,079
2016	May	32,883	120,132	2,977	6,006
2016	Jun	35,469	151,414	2,528	6,406
2016	Jul	37,668	181,720	2,413	7,158
2016	Aug	32,986	147,289	2,294	6,774
2016	Sep	29,368	129,498	2,309	6,065
2016	Oct	28,250	121,377	2,612	6,498
2016	Nov	36,506	141,491	2,927	7,324
2016	Dec	40,090	147,343	3,552	8,803
2016	Annual	34,387	142,075	2,549	6,503
2017	Jan	46,856	196,472	3,568	10,246
2017	Feb	41,841	207,994	2,711	8,309
2017	Mar	38,780	164,063	2,272	6,252
2017	Apr	42,274	152,868	2,247	6,022
2017	May	34,477	116,688	1,962	4,957
2017	Jun	29,996	112,071	1,801	4,839
2017	Jul	32,287	118,609	1,875	5,108
2017	Aug	31,511	122,677	1,931	5,062
2017	Sep	30,485	120,956	1,740	4,423
2017	Annual	36,478	145,467	2,235	6,134

Table 3-44 shows the average hourly number of import and export transactions and the average hourly MW in 2016 and first nine months of 2017. In the first nine months of 2017, the average hourly submitted and cleared import transaction MW decreased by 60.5 and 62.5 percent, and the average hourly submitted and cleared export transaction MW increased 8.4 and 5.4 percent, compared to the first nine months of 2016.

Table 3-44 Hourly average day-ahead number of cleared and submitted import and export transactions by month: January 1, 2016 through September 30, 2017

		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
2016	Jan	2,633	2,103	20	20	3,044	2,571	16	16
2016	Feb	2,396	2,480	20	22	2,634	2,653	13	13
2016	Mar	2,097	2,145	17	18	2,324	2,330	11	11
2016	Apr	2,150	2,180	16	16	2,620	2,635	13	13
2016	May	1,889	1,947	12	14	2,484	2,492	14	15
2016	Jun	1,335	1,366	6	7	4,428	4,471	23	24
2016	Jul	1,315	1,247	6	6	4,327	3,389	21	21
2016	Aug	1,384	1,424	6	7	4,331	4,351	20	20
2016	Sep	939	956	5	5	3,997	4,004	21	21
2016	Oct	1,104	997	6	6	3,800	2,902	22	22
2016	Nov	1,012	1,030	6	7	2,883	2,894	17	17
2016	Dec	1,302	1,354	8	9	4,284	4,306	22	22
2016	Annual	1,628	1,600	11	11	3,434	3,250	18	17
2017	Jan	1,264	1,289	6	6	3,169	3,171	16	16
2017	Feb	1,379	1,418	7	8	3,540	3,552	18	19
2017	Mar	1,125	1,157	6	7	3,791	3,813	18	18
2017	Apr	521	526	3	3	2,475	2,483	14	14
2017	May	188	201	4	4	2,805	2,817	18	18
2017	Jun	248	255	3	4	2,705	2,730	16	16
2017	Jul	308	309	2	3	2,605	2,643	14	14
2017	Aug	368	362	2	2	2,505	2,556	12	12
2017	Sep	428	416	1	2	2,405	2,469	9	10
2017	Annual	782	802	5	6	3,079	3,092	17	17

Table 3-45 shows the frequency with which generation offers, import or export transactions, up to congestion transactions, decrement bids, increment offers and price-sensitive demand were marginal from January 1, 2016, through September 30, 2017.

Table 3-45 Type of day-ahead marginal units: January 1, 2016 through September 30, 2017

	2016						2017				
	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
Jan	5.3%	0.1%	85.2%	5.6%	3.8%	0.0%	3.2%	0.0%	85.3%	7.7%	3.7%
Feb	5.5%	0.0%	83.5%	7.4%	3.6%	0.0%	4.9%	0.0%	83.9%	6.5%	4.6%
Mar	7.0%	0.1%	80.6%	7.7%	4.7%	0.0%	4.3%	0.1%	81.5%	8.5%	5.6%
Apr	5.8%	0.0%	82.3%	8.1%	3.7%	0.0%	2.8%	0.0%	83.4%	8.9%	4.9%
May	6.2%	0.1%	83.8%	6.5%	3.4%	0.0%	3.5%	0.0%	77.4%	11.8%	7.2%
Jun	3.5%	0.0%	84.2%	8.5%	3.7%	0.0%	4.3%	0.0%	73.5%	15.4%	6.7%
Jul	3.0%	0.0%	83.1%	10.1%	3.7%	0.0%	2.9%	0.0%	77.1%	13.6%	6.4%
Aug	3.1%	0.0%	78.4%	13.1%	5.4%	0.0%	3.8%	0.0%	81.8%	9.0%	5.4%
Sep	6.1%	0.0%	76.3%	11.4%	6.2%	0.0%	6.6%	0.0%	77.8%	9.8%	5.8%
Oct	6.1%	0.1%	77.0%	10.9%	5.9%	0.0%					
Nov	4.0%	0.0%	86.5%	6.3%	3.1%	0.0%					
Dec	3.1%	0.0%	86.6%	6.9%	3.3%	0.0%					
Annual	4.7%	0.0%	82.4%	8.6%	4.2%	0.0%	4.0%	0.0%	80.4%	10.1%	5.5%

Figure 3-35 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month from January 1, 2005, through September 30, 2017.

Figure 3-35 Monthly bid and cleared INCs, DECs and UTCs (MW): January 1, 2005 through September 30, 2017

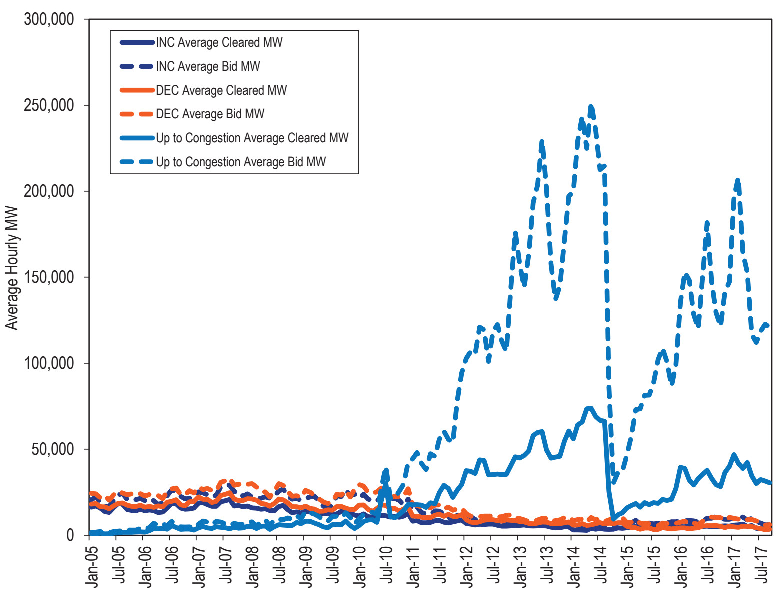
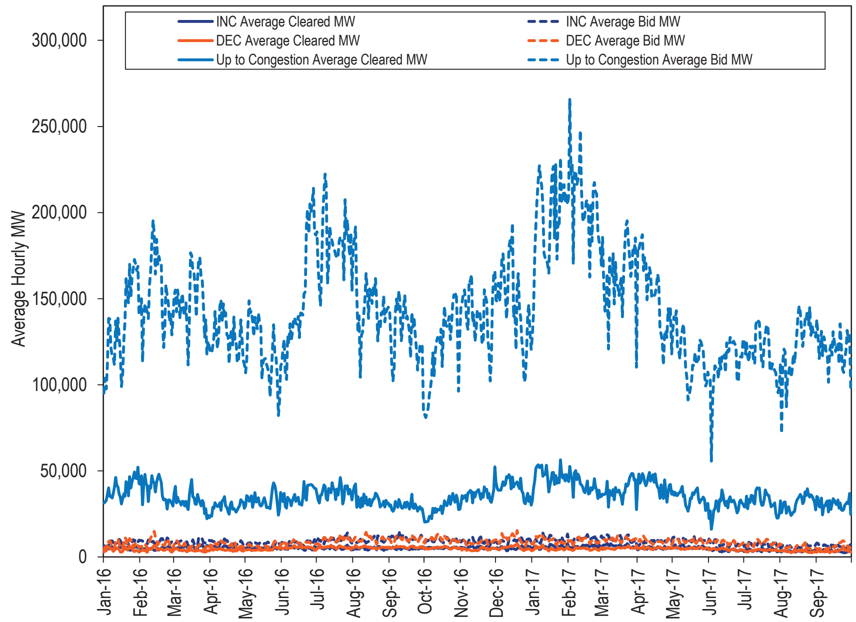


Figure 3-36 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 1, 2016 through September 30, 2017.

Figure 3-36 Daily bid and cleared INCs, DECs, and UTCs (MW): January 1, 2016 through September 30, 2017



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 3-46 shows, in the first nine months of 2016 and 2017, the total increment offers and decrement bids and cleared MW by whether the parent organization is financial or physical.

Table 3-46 PJM INC and DEC bids and cleared MW by type of parent organization (MW): January 1 through September 30, 2016 and 2017

	Jan-Sep 2016				Jan-Sep 2017			
Category	Total Virtual Bid MW	Percent	Total Virtual Cleared MW	Percent	Total Virtual Bid MW	Percent	Total Virtual Cleared MW	Percent
Financial	61,124,874	54.1%	21,936,954	33.7%	65,722,185	59.5%	26,832,370	44.2%
Physical	51,819,249	45.9%	43,249,868	66.3%	44,791,770	40.5%	33,908,176	55.8%
Total	112,944,124	100.0%	65,186,822	100.0%	110,513,955	100.0%	60,740,546	100.0%

Table 3-47 shows, in the first nine months of 2016 and 2017, the total up to congestion bids and cleared MW by whether the parent organization was financial or physical.

Table 3-47 PJM up to congestion transactions by type of parent organization (MW): January 1 through September 30, 2016 and 2017

	Jan-Sep 2016				Jan-Sep 2017			
Category	Total Up to Congestion Bid MW	Percent	Total Up to Congestion Cleared MW	Percent	Total Up to Congestion Bid MW	Percent	Total Up to Congestion Cleared MW	Percent
Financial	904,636,563	95.6%	209,224,861	93.0%	931,474,310	98.1%	228,911,492	96.1%
Physical	41,404,176	4.4%	15,648,427	7.0%	17,985,716	1.9%	9,178,854	3.9%
Total	946,040,739	100.0%	224,873,289	100.0%	949,460,026	100.0%	238,090,346	100.0%

Table 3-48 shows, in the first nine months of 2016 and 2017, the total import and export transactions by whether the parent organization was financial or physical.

Table 3-48 PJM import and export transactions by type of parent organization (MW): January 1 through September 30, 2016 and 2017

		Jan-Sep 2016		Jan-Sep 2017	
	Category	Total Import and Export MW	Percent	Total Import and Export MW	Percent
Day-Ahead	Financial	14,036,369	41.5%	9,725,219	39.7%
	Physical	19,813,715	58.5%	14,790,242	60.3%
	Total	33,850,084	100.0%	24,515,462	100.0%
Real-Time	Financial	19,648,594	34.4%	17,003,782	38.8%
	Physical	37,488,532	65.6%	26,834,587	61.2%
	Total	57,137,126	100.0%	43,838,369	100.0%

Table 3-49 shows increment offers and decrement bids bid by top 10 locations in the first nine months of 2016 and 2017.

Table 3-49 PJM virtual offers and bids by top 10 locations (MW): January 1 through September 30, 2016 and 2017

Jan-Sep 2016					Jan-Sep 2017				
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	17,601,316	16,931,839	34,533,154	WESTERN HUB	HUB	16,303,266	12,276,948	28,580,213
MISO	INTERFACE	330,509	3,360,916	3,691,425	MISO	INTERFACE	221,785	5,278,718	5,500,503
SOUTHIMP	INTERFACE	3,052,550	0	3,052,550	AEP-DAYTON HUB	HUB	2,055,810	508,370	2,564,180
N ILLINOIS HUB	HUB	935,621	1,832,960	2,768,582	NYIS	INTERFACE	1,232,270	1,042,835	2,275,104
NYIS	INTERFACE	1,245,580	941,396	2,186,976	N ILLINOIS HUB	HUB	457,428	1,689,308	2,146,736
BGE	ZONE	397,423	1,787,677	2,185,100	SOUTHIMP	INTERFACE	1,999,033	0	1,999,033
AEP-DAYTON HUB	HUB	1,010,667	634,063	1,644,729	FOWLER 34.5 KV FWLR1AWF	GEN	366,891	1,193,753	1,560,644
PEPCO	ZONE	390,455	645,873	1,036,328	DCKCRKCE345 KV UN1 DYN	GEN	1,086,888	445,631	1,532,519
IMO	INTERFACE	947,847	44,607	992,453	BGE	ZONE	327,412	1,072,672	1,400,084
PECO	ZONE	704,416	214,326	918,742	PEPCO	ZONE	400,553	542,606	943,159
Top ten total		26,616,383	26,393,656	53,010,039			24,451,336	24,050,840	48,502,176
PJM total		58,672,006	54,272,117	112,944,124			55,822,362	54,691,593	110,513,955
Top ten total as percent of PJM total		45.4%	48.6%	46.9%			43.8%	44.0%	43.9%

Table 3-50 shows up to congestion transactions by import bids for the top 10 locations and associated profits at each path in the first nine months of 2016 and 2017.[62]

62 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 3-50 PJM cleared up to congestion import bids by top 10 source and sink pairs (MW): January 1 through September 30, 2016 and 2017

Jan-Sep 2016							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	COOK	EHVAGG	420,275	$81,672	$27,211	$108,883
HUDSONTP	INTERFACE	LEONIA 230 T-2	AGGREGATE	412,447	$987,993	($956,659)	$31,334
SOUTHWEST	INTERFACE	DUMONT	EHVAGG	402,413	$9,043	($20,474)	($11,431)
NEPTUNE	INTERFACE	SOUTHRIV 230	AGGREGATE	387,958	$383,410	($197,930)	$185,480
MISO	INTERFACE	112 WILTON	EHVAGG	346,995	$455,544	($347,208)	$108,336
SOUTHIMP	INTERFACE	NAGELAEP	EHVAGG	311,554	$266,334	($360,165)	($93,831)
OVEC	INTERFACE	COOK	EHVAGG	297,528	$146,628	($54,084)	$92,544
NORTHWEST	INTERFACE	COMED	ZONE	283,823	$54,942	($29,765)	$25,177
SOUTHWEST	INTERFACE	COOK	EHVAGG	267,209	$21,575	$54,108	$75,684
OVEC	INTERFACE	DEOK	ZONE	267,145	$232,491	($179,793)	$52,698
Top ten total				3,397,349	$2,639,632	($2,064,758)	$574,874
PJM total				20,730,628	$13,599,867	($9,478,576)	$4,121,291
Top ten total as percent of PJM total				16.4%	19.4%	21.8%	13.9%
Jan-Sep 2017							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	COOK	EHVAGG	854,805	$521,201	($354,941)	$166,260
HUDSONTP	INTERFACE	LEONIA 230 T-2	AGGREGATE	466,687	$150,439	($147,219)	$3,220
NYIS	INTERFACE	PSEG	ZONE	372,599	$527,718	($582,513)	($54,795)
SOUTHEAST	INTERFACE	WEST INT HUB	HUB	369,699	$197,151	($151,637)	$45,514
OVEC	INTERFACE	DEOK	ZONE	319,538	$193,104	($64,012)	$129,092
OVEC	INTERFACE	ATSI	ZONE	277,086	$60,419	$116,940	$177,359
SOUTHEAST	INTERFACE	VP KERR DAM 1-7	AGGREGATE	265,948	$212,672	($155,282)	$57,390
NORTHWEST	INTERFACE	COMED	ZONE	241,666	$73,282	$94,586	$167,867
SOUTHEAST	INTERFACE	WILLIAMSPORT - AP	AGGREGATE	229,512	$297,905	($226,827)	$71,077
OVEC	INTERFACE	SPORN 1	AGGREGATE	226,980	$137,726	($111,796)	$25,930
Top ten total				3,624,519	$2,371,616	($1,582,701)	$788,915
PJM total				17,758,402	$12,260,566	($10,137,747)	$2,122,819
Top ten total as percent of PJM total				20.4%	19.3%	15.6%	37.2%

Table 3-51 shows up to congestion transactions by export bids for the top 10 locations and associated profits at each path in the first nine months of 2016 and 2017.

Table 3-51 PJM cleared up to congestion export bids by top 10 source and sink pairs (MW): January 1 through September 30, 2016 and 2017

Jan-Sep 2016							
Exports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
COMED	ZONE	NIPSCO	INTERFACE	1,193,829	$922,273	$386,705	$1,308,978
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	816,704	$873,223	($692,677)	$180,546
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	796,526	$916,708	($630,209)	$286,499
21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	680,935	$623,866	$135,178	$759,045
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	357,690	($73,298)	$149,178	$75,879
21 KINCA ATR24404	AGGREGATE	SOUTHWEST	INTERFACE	355,384	($72,043)	$234,560	$162,517
STMARYSGEN	AGGREGATE	NIPSCO	INTERFACE	351,173	$218,264	($143,020)	$75,244
EAST BEND 2	AGGREGATE	SOUTHWEST	INTERFACE	320,779	$220,091	($151,543)	$68,549
GRAND RIDGE WF	AGGREGATE	NIPSCO	INTERFACE	312,809	$164,772	$58,445	$223,217
CLOVERDALE	EHVAGG	SOUTHEXP	INTERFACE	312,039	$253,486	($141,037)	$112,449
Top ten total				5,497,868	$4,047,342	($794,420)	$3,252,922
PJM total				16,874,053	$10,543,810	($3,181,309)	$7,362,501
Top ten total as percent of PJM total				32.6%	38.4%	25.0%	44.2%
Jan-Sep 2017							
Exports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
JEFFERSON	EHVAGG	SOUTHWEST	INTERFACE	948,831	$1,095,813	($824,364)	$271,450
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	785,957	$462,812	($331,760)	$131,051
COMED	ZONE	NIPSCO	INTERFACE	733,390	$179,536	$767,350	$946,886
SULLIVAN-AEP	EHVAGG	SOUTHWEST	INTERFACE	391,617	$144,407	($51,237)	$93,170
JEFFERSON	EHVAGG	NIPSCO	INTERFACE	386,653	$401,933	($294,436)	$107,497
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	384,148	$104,896	($92,301)	$12,595
21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	349,219	$118,071	($84,517)	$33,554
POWERTON 5	AGGREGATE	NORTHWEST	INTERFACE	295,770	($118,521)	$5,332	($113,190)
GENEVA	AGGREGATE	NIPSCO	INTERFACE	287,642	$246,941	($263,806)	($16,865)
QUAD CITIES 2	AGGREGATE	MISO	INTERFACE	280,514	$11,169	($6,960)	$4,210
Top ten total				4,843,740	$2,647,058	($1,176,699)	$1,470,359
PJM total				16,060,146	$5,192,338	($113,341)	$5,078,997
Top ten total as percent of PJM total				30.2%	51.0%	1038.2%	28.9%

Table 3-52 shows up to congestion transactions by wheel bids and associated profits at each path for the top 10 locations in the first nine months of 2016 and 2017.

Table 3-52 PJM cleared up to congestion wheel bids by top 10 source and sink pairs (MW): January 1 through September 30, 2016 and 2017

Jan-Sep 2016							
Wheels							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	MISO	INTERFACE	368,290	$68,502	$25,240	$93,742
MISO	INTERFACE	NIPSCO	INTERFACE	347,090	$318,960	($72,526)	$246,434
NYIS	INTERFACE	IMO	INTERFACE	234,305	$17,005	$42,083	$59,088
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	185,952	$289,962	($207,680)	$82,282
MISO	INTERFACE	NORTHWEST	INTERFACE	157,480	$107,182	($12,516)	$94,666
IMO	INTERFACE	NYIS	INTERFACE	120,984	$80,681	($134,532)	($53,850)
SOUTHWEST	INTERFACE	NIPSCO	INTERFACE	78,789	$92,987	($51,023)	$41,964
IMO	INTERFACE	MISO	INTERFACE	50,526	$32,174	($59,262)	($27,088)
MISO	INTERFACE	SOUTHEXP	INTERFACE	36,874	$102,954	($75,081)	$27,874
NEPTUNE	INTERFACE	NYIS	INTERFACE	32,018	$41,928	($35,602)	$6,326
Top ten total				1,612,308	$1,152,335	($580,899)	$571,436
PJM total				1,883,658	$1,306,706	($651,436)	$655,270
Top ten total as percent of PJM total				85.6%	88.2%	89.2%	87.2%
Jan-Sep 2017							
Wheels							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	NIPSCO	INTERFACE	256,570	$285,988	($164,424)	$121,564
NORTHWEST	INTERFACE	MISO	INTERFACE	213,680	$214,802	($60,349)	$154,452
MISO	INTERFACE	NORTHWEST	INTERFACE	197,138	$88,379	($79,447)	$8,932
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	173,826	$350,520	($330,303)	$20,217
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	63,521	$10,902	$89,325	$100,226
SOUTHWEST	INTERFACE	NIPSCO	INTERFACE	54,387	$56,776	($18,685)	$38,091
OVEC	INTERFACE	SOUTHWEST	INTERFACE	26,050	($10,819)	$14,112	$3,293
SOUTHIMP	INTERFACE	MISO	INTERFACE	15,616	($654)	$19,407	$18,753
MISO	INTERFACE	SOUTHWEST	INTERFACE	15,377	($4,322)	$5,687	$1,365
NORTHWEST	INTERFACE	SOUTHWEST	INTERFACE	15,224	($17,536)	$14,618	($2,917)
Top ten total				1,031,389	$974,036	($510,060)	$463,976
PJM total				1,226,777	$1,084,615	($589,413)	$495,202
Top ten total as percent of PJM total				84.1%	89.8%	86.5%	93.7%

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 10 internal up to congestion transaction locations were 5.5 percent of the PJM total internal up to congestion transactions MW in the first nine months of 2017.

Table 3-53 shows up to congestion transactions by internal bids for the top 10 locations and associated profits at each path in the first nine months of 2016 and 2017. The total UTC profit by top 10 locations decreased by $0.6 million, from $2.5 million in the first nine months of 2016 to $1.9 million in the first nine months of 2017. The total internal cleared MW increased by 18.5 million MW, or 10.0 percent, from 185.4 million MW in the first nine months of 2016 to 203.8 million MW in the first nine months of 2017.

Table 3-53 PJM cleared up to congestion internal bids by top 10 source and sink pairs (MW): January 1 through September 30, 2016 and 2017

				Jan-Sep 2016			
				Internal			
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
21 KINCA ATR24304	AGGREGATE	MICHFE	AGGREGATE	1,644,791	$79,429	$336,092	$415,520
21 KINCA ATR24404	AGGREGATE	MICHFE	AGGREGATE	1,187,493	($400,827)	$527,561	$126,734
BERGEN 2CC	AGGREGATE	LEONIA 230 T-1	AGGREGATE	991,052	$1,995,116	($1,991,033)	$4,084
BYRON 1	AGGREGATE	ROCKFORD	AGGREGATE	956,523	$837,695	$367,038	$1,204,733
ROCKPORT	EHVAGG	JEFFERSON	EHVAGG	847,431	$682,497	($606,096)	$76,402
BLACKOAK	EHVAGG	BEDINGTON	EHVAGG	775,892	$506,532	($1,054,900)	($548,369)
112 WILTON	EHVAGG	DUMONT	EHVAGG	763,018	$356,648	($313,595)	$43,054
CLOVERDALE	EHVAGG	CLOVERD2 138 KV T4	AGGREGATE	758,676	$541,175	$577,399	$1,118,575
BRISTERS	EHVAGG	OX	EHVAGG	740,821	$974,035	($903,879)	$70,157
WHIPPANY BK 7	AGGREGATE	TRAYNOR	AGGREGATE	740,246	$537,051	($517,714)	$19,338
Top ten total				9,405,943	$6,109,352	($3,579,126)	$2,530,226
PJM total				185,384,950	$109,392,657	($86,319,972)	$23,072,685
Top ten total as percent of PJM total				5.1%	5.6%	4.1%	11.0%
				Jan-Sep 2017			
				Internal			
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
DUMONT	EHVAGG	COOK	EHVAGG	2,122,722	$1,066,199	($771,161)	$295,038
AEP-DAYTON HUB	HUB	N ILLINOIS HUB	HUB	1,210,561	$34,835	$42,024	$76,860
JEFFERSON	EHVAGG	OHIO HUB	HUB	1,125,462	$873,830	($525,924)	$347,906
BAKER	EHVAGG	AMP-OHIO	AGGREGATE	1,117,855	$182,468	$139,340	$321,808
STUART 3	AGGREGATE	MICHFE	AGGREGATE	1,111,651	$66,977	$290,770	$357,746
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	1,101,271	$297,706	($136,041)	$161,665
FE GEN	AGGREGATE	ATSI	ZONE	1,033,870	($449,838)	$625,110	$175,273
WINNETKA	AGGREGATE	CHICAGO HUB	HUB	801,143	$322,998	($223,897)	$99,101
HOMERCIT	AGGREGATE	AEC - PN	AGGREGATE	799,122	$485,266	($473,412)	$11,854
NORTH PROCTORVILLE	EHVAGG	APS	ZONE	796,992	$365,102	($326,300)	$38,802
Top ten total				11,220,648	$3,245,543	($1,359,490)	$1,886,053
PJM total				203,847,327	$61,135,224	($34,975,367)	$26,159,857
Top ten total as percent of PJM total				5.5%	5.3%	3.9%	7.2%

Table 3-54 shows the number of source-sink pairs that were offered and cleared monthly for January 2016 through September 2017.

Table 3-54 Number of PJM offered and cleared source and sink pairs: January 1, 2016 through September 30, 2017

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2016	Jan	7,714	8,793	6,174	7,374
2016	Feb	9,200	11,172	7,203	7,957
2016	Mar	8,826	11,572	6,338	8,126
2016	Apr	7,697	8,473	5,958	6,767
2016	May	8,521	9,398	6,707	7,273
2016	Jun	9,261	10,948	6,913	7,770
2016	Jul	12,401	16,103	8,571	11,695
2016	Aug	12,464	13,576	8,725	9,224
2016	Sep	12,297	16,324	7,736	9,230
2016	Oct	11,248	13,114	7,648	8,539
2016	Nov	13,151	16,725	8,173	11,581
2016	Dec	12,688	15,868	8,101	9,630
2016	Annual	10,455	12,672	7,354	8,764
2017	Jan	11,893	13,258	7,785	8,839
2017	Feb	9,337	11,902	6,756	7,758
2017	Mar	7,795	8,776	6,051	7,001
2017	Apr	8,168	8,805	6,494	7,172
2017	May	7,988	9,117	6,504	7,294
2017	Jun	9,776	13,012	5,822	6,228
2017	Jul	12,726	13,334	5,960	6,481
2017	Aug	12,966	15,729	6,578	7,201
2017	Sep	7,758	9,229	6,030	7,162
2017	Jan-Sep	9,823	11,462	6,442	7,237

Table 3-55 and Figure 3-37 show total cleared up to congestion transactions by type in the first nine months of 2016 and 2017. Total up to congestion transactions in the first nine months of 2017 increased by 5.9 percent from 224.9 million MW in the first nine months of 2016 to 238.1 million MW in the first nine months of 2017. Internal up to congestion transactions in the first nine months of 2017 were 85.3 percent of all up to congestion transactions compared to 82.4 percent in the first nine months of 2016.

Table 3-55 PJM cleared up to congestion transactions by type (MW): January 1 through September 30, 2016 and 2017

	Jan-Sep 2016				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	3,397,349	5,497,868	1,612,308	9,405,943	19,913,468
PJM total (MW)	20,730,628	16,874,053	1,883,658	185,384,950	224,873,289
Top ten total as percent of PJM total	16.4%	32.6%	85.6%	5.1%	8.9%
PJM total as percent of all up to congestion transactions	9.2%	7.5%	0.8%	82.4%	100.0%
	Jan-Sep 2017				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	3,624,519	4,843,740	1,031,389	11,220,648	20,720,296
PJM total (MW)	17,758,402	16,060,146	1,226,777	203,847,327	238,892,652
Top ten total as percent of PJM total	20.4%	30.2%	84.1%	5.5%	8.7%
PJM total as percent of all up to congestion transactions	7.4%	6.7%	0.5%	85.3%	100.0%

Figure 3-37 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. The reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed. There was an increase in up to congestion volume as a result of the expiration of the fifteen month refund period for the proceeding related to uplift charges for UTC transactions.[63]

63 *Id.*

Figure 3-37 PJM monthly cleared up to congestion transactions by type (MW): January 1, 2005, through September 30, 2017

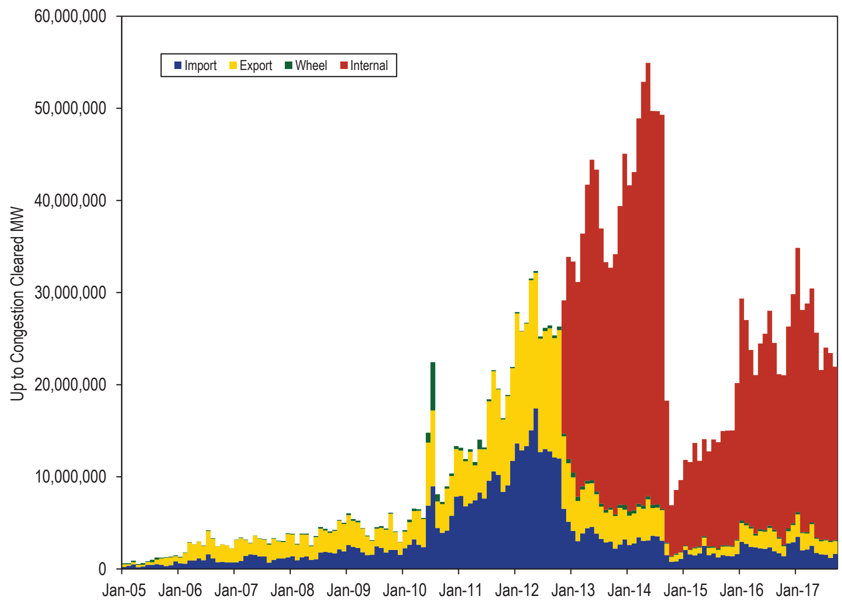
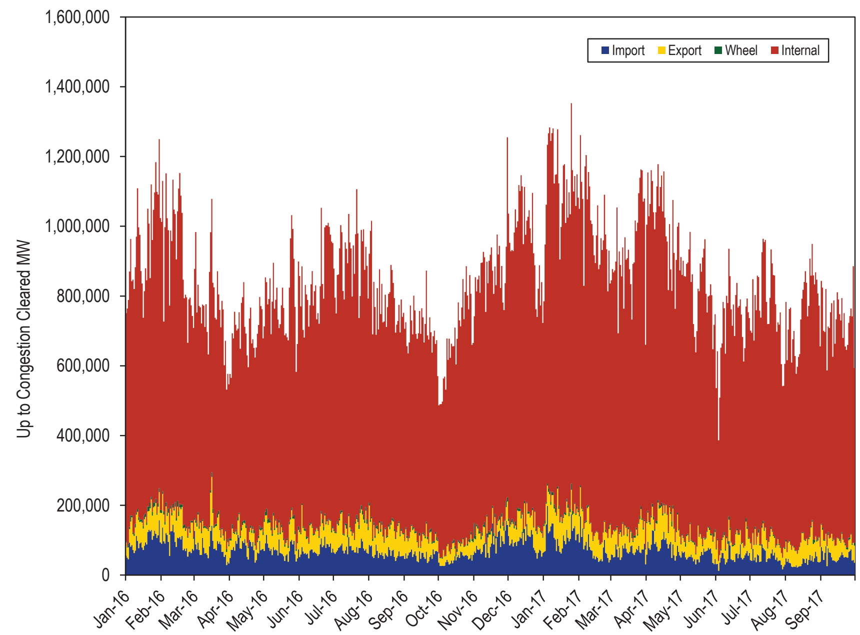


Figure 3-38 shows the daily cleared up to congestion MW by transaction type from January 1, 2016 through September 30, 2017.

Figure 3-38 PJM daily cleared up to congestion transaction by type (MW): January 1, 2016, through September 30, 2017



Market Performance

PJM locational marginal prices (LMPs) are a direct measure of market performance. The market performs optimally when the market structure provides incentives for market participants to behave competitively. With price formation in a competitive market, prices equal the value of the marginal unit of output and reflect the most efficient and least cost allocation of resources to meet demand.

Markup

The markup index is a measure of the competitiveness of participant behavior for individual units. The markup in dollars is a measure of the impact of participant behavior on the generator bus market price when a unit is marginal. 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 index 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 have different impacts on total system price. Markup can also affect prices when units with high markups are not marginal by altering the economic dispatch order of supply.

The MMU calculates an explicit measure of the impact of marginal unit markups on LMP using the mathematical relationships among LMPs in the market solution.[64] The markup impact calculation sums, over all marginal units, the product of the dollar markup of the unit and the marginal impact of the unit's offer on the system load-weighted LMP. The markup impact includes the impact of the identified markup behavior of all marginal units. Positive and negative markup impacts may offset one another. The markup analysis is a direct measure of market performance. It does not take into account whether or not marginal units have either locational or aggregate structural market power.

The markup calculation is not based on a counterfactual 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 short run marginal cost. 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 short run 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 short run 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.

64 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 LMP based on a comparison between the price-based offer and the cost-based offer of each actual marginal unit on the system. This is the same method used to calculate the fuel cost adjusted LMP and the components of LMP. *See* Calculation and Use of Generator Sensitivity/Unit Participation Factors, 2010 State of the Market Report for PJM: Technical Reference for PJM Markets.

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 3-56 shows the impact (markup component of LMP) of the markup behavior by fuel type and unit type on the real-time load-weighted average system LMP, using unadjusted and adjusted offers. The adjusted markup component of LMP increased from $2.36 per MWh in the first nine months of 2016 to $4.74 per MWh in the first nine months of 2017. The adjusted markup contribution of coal units in the first nine months of 2017 was $0.10 per MWh. The adjusted mark-up component of gas fired units in the first nine months of 2017 was $3.41 per MWh, an increase of $1.05 per MWh from the first nine months of 2016. The markup component of wind units was $0.06 per MWh. 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 2017, among the wind units that were marginal, 6.9 percent had positive offer prices.

Table 3-56 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January 1 through September 30, 2016 and 2017[65]

		2016 (Jan-Sep)		2017 (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	($1.48)	$0.10	$0.22	$1.28
Gas	CC	$1.10	$1.55	$1.86	$2.86
Gas	CT	$0.17	$0.38	$0.27	$0.44
Gas	Diesel	$0.00	$0.00	($0.00)	$0.00
Gas	Steam	$0.29	$0.43	$0.03	$0.11
Municipal Waste	Diesel	$0.01	$0.01	$0.00	$0.00
Municipal Waste	Steam	($0.00)	($0.00)	$0.00	$0.00
Oil	CC	$0.00	$0.00	$0.00	$0.00
Oil	CT	$0.01	$0.04	($0.06)	($0.04)
Oil	Diesel	$0.00	$0.00	$0.00	$0.00
Oil	Steam	$0.00	$0.00	($0.00)	$0.00
Other	Steam	($0.18)	($0.18)	$0.02	$0.02
Uranium		$0.00	$0.00	$0.00	$0.00
Wind		$0.02	$0.02	$0.06	$0.06
Total		($0.05)	$2.36	$2.41	$4.74

Markup Component of Real-Time Price

Table 3-57 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3- 58 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 2017, when using unadjusted cost offers, $2.41 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost offers, $4.74 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first nine months of 2017, the peak markup component was highest in May, $5.51 per MWh using unadjusted cost offers and $8.23 per MWh using adjusted cost offers. This corresponds to 14.54 percent and 21.72 percent of the real-time peak load-weighted average LMP in May.

65 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 3-57 Monthly markup components of real-time load-weighted LMP (Unadjusted): January 1 through September 30, 2016 and 2017

	2016			2017		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($1.89)	($1.95)	($1.82)	$1.75	$0.47	$3.11
Feb	($0.43)	($0.59)	($0.28)	$1.13	$0.53	$1.70
Mar	($1.24)	($1.22)	($1.25)	$1.12	$1.70	$0.60
Apr	$0.32	($0.82)	$1.41	$1.87	$0.93	$2.86
May	($1.68)	($1.13)	($2.24)	$2.91	($0.01)	$5.51
Jun	$0.86	$0.60	$1.07	$3.08	$0.93	$4.88
Jul	($0.06)	($1.02)	$0.89	$3.63	$2.16	$5.14
Aug	$1.18	$0.10	$2.06	$2.69	$1.11	$3.94
Sep	$2.23	$1.25	$3.12	$3.17	$1.46	$4.86
Total	($0.04)	($0.56)	$0.44	$2.41	$1.07	$3.67

Table 3-58 Monthly markup components of real-time load-weighted LMP (Adjusted): January 1 through September 30, 2016 and 2017

	2016			2017		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$0.76	$0.44	$1.12	$4.43	$3.07	$5.88
Feb	$1.98	$1.55	$2.39	$3.33	$2.60	$4.03
Mar	$0.63	$0.49	$0.76	$3.58	$3.82	$3.37
Apr	$2.61	$1.32	$3.85	$4.01	$2.95	$5.12
May	$0.35	$0.65	$0.06	$5.33	$2.07	$8.23
Jun	$3.10	$2.54	$3.58	$5.29	$2.85	$7.33
Jul	$2.64	$1.19	$4.08	$6.10	$4.29	$7.96
Aug	$4.02	$2.39	$5.35	$4.89	$3.04	$6.35
Sep	$4.58	$3.25	$5.79	$5.27	$3.37	$7.13
Total	$2.37	$1.53	$3.15	$4.74	$3.16	$6.21

Hourly Markup Component of Real-Time Prices

Figure 3-39 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in the first nine months of 2017 and 2016. Figure 3-40 shows the markup contribution to the hourly load-weighted LMP using adjusted cost offers in the first nine months of 2017 and 2016.

Figure 3-39 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): January 1 through September 30, 2016 and 2017

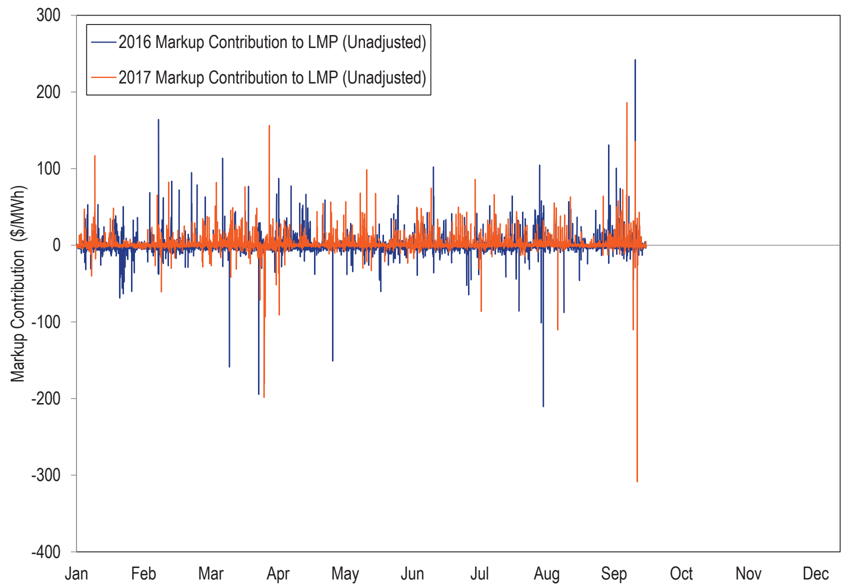
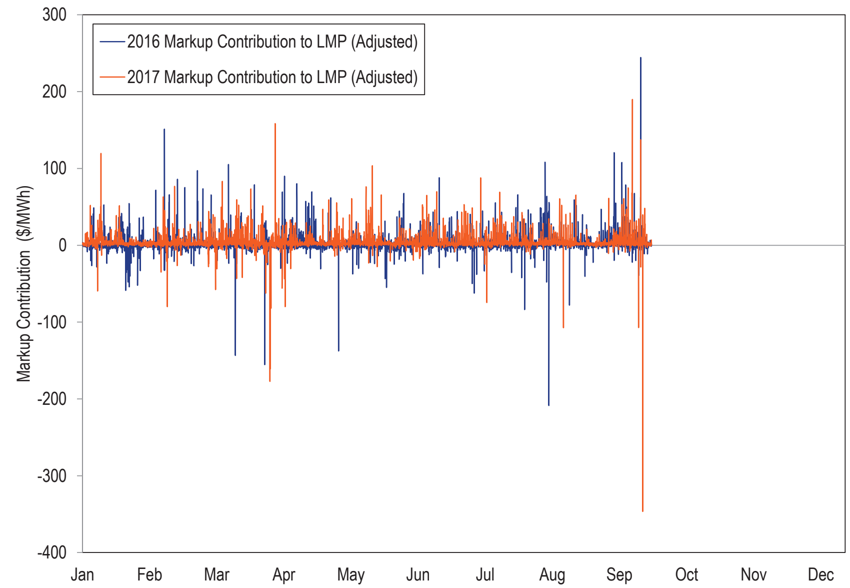


Figure 3-40 Markup contribution to real-time hourly load-weighted LMP (Adjusted): January 1 through September 30, 2016 and 2017



Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone in the first nine months of 2016 and 2017 in Table 3-59 and for adjusted offers in Table 3-60. The smallest zonal all hours average markup component using unadjusted offers in the first nine months of 2017 was in the Met-Ed Zone, $1.86 per MWh, while the highest was in the BGE Control Zone, $3.00 per MWh. The smallest zonal on peak average markup was in the RECO Control Zone, $2.49 per MWh, while the highest was in the BGE Control Zone, $4.60 per MWh.

Table 3-59 Average real-time zonal markup component (Unadjusted): January 1 through September 30, 2016 and 2017

	2016 (Jan-Sep)			2017(Jan-Sep)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$0.99	$0.55	$1.40	$2.11	$1.21	$2.98
AEP	($0.44)	($0.94)	$0.04	$2.26	$1.03	$3.43
APS	($0.30)	($0.84)	$0.21	$2.37	$0.98	$3.70
ATSI	($0.23)	($0.87)	$0.37	$2.35	$1.08	$3.53
BGE	($1.33)	($2.21)	($0.49)	$3.00	$1.31	$4.60
ComEd	($0.11)	($0.68)	$0.40	$2.35	$0.92	$3.66
DAY	($0.48)	($0.88)	($0.13)	$2.34	$1.09	$3.47
DEOK	($0.33)	($0.84)	$0.15	$2.43	$1.09	$3.70
DLCO	($0.03)	($0.72)	$0.61	$2.38	$1.00	$3.67
DPL	$1.44	$0.84	$2.02	$2.37	$1.48	$3.21
Dominion	($0.61)	($0.97)	($0.26)	$2.85	$1.17	$4.46
EKPC	($0.40)	($0.59)	($0.21)	$2.26	$1.03	$3.50
JCPL	$1.15	$0.71	$1.55	$2.49	$1.21	$3.64
Met-Ed	$0.77	$0.54	$0.97	$1.86	$0.74	$2.90
PECO	$1.30	$0.68	$1.87	$2.13	$1.07	$3.13
PENELEC	$0.11	($0.40)	$0.59	$2.42	$1.31	$3.45
PPL	$0.95	$0.52	$1.36	$1.95	$0.75	$3.08
PSEG	$1.04	$0.64	$1.40	$2.48	$1.16	$3.69
Pepco	($0.95)	($1.46)	($0.48)	$2.73	$1.13	$4.20
RECO	$1.08	$0.51	$1.57	$1.95	$1.31	$2.49

Table 3-60 Average real-time zonal markup component (Adjusted): January 1 through September 30, 2016 and 2017

	2016 (Jan-Sep)			2017 (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	$3.13	$2.38	$3.86	$4.33	$3.19	$5.42
AEP	$1.98	$1.18	$2.73	$4.58	$3.16	$5.95
APS	$2.18	$1.33	$2.99	$4.73	$3.12	$6.28
ATSI	$2.23	$1.25	$3.13	$4.82	$3.27	$6.25
BGE	$1.86	$0.63	$3.04	$5.52	$3.48	$7.45
ComEd	$2.20	$1.28	$3.04	$4.56	$2.91	$6.07
DAY	$1.95	$1.26	$2.58	$4.75	$3.26	$6.11
DEOK	$2.03	$1.24	$2.76	$4.73	$3.19	$6.18
DLCO	$2.39	$1.35	$3.37	$4.77	$3.15	$6.28
DPL	$3.73	$2.79	$4.62	$4.71	$3.67	$5.70
Dominion	$2.13	$1.43	$2.80	$5.23	$3.34	$7.05
EKPC	$1.97	$1.52	$2.41	$4.55	$3.15	$5.95
JCPL	$3.24	$2.47	$3.93	$4.73	$3.21	$6.11
Met-Ed	$2.81	$2.24	$3.32	$4.21	$2.72	$5.58
PECO	$3.31	$2.39	$4.18	$4.31	$3.05	$5.48
PENELEC	$2.39	$1.55	$3.17	$4.78	$3.43	$6.02
PPL	$2.95	$2.23	$3.61	$4.18	$2.75	$5.50
PSEG	$3.13	$2.37	$3.84	$4.73	$3.14	$6.20
Pepco	$1.91	$1.07	$2.68	$5.16	$3.27	$6.91
RECO	$3.24	$2.27	$4.07	$4.24	$3.36	$5.00

Markup by Real Time Price Levels

Table 3-61 shows the average markup component of LMP, 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 3-61 Average real-time markup component (By price category, unadjusted): January 1 through September 30, 2016 and 2017

	2016 (Jan-Sep)		2017 (Jan-Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.98)	59.6%	($0.11)	49.0%
$25 to $50	($0.32)	34.6%	$1.18	45.2%
$50 to $75	$0.61	3.7%	$0.89	4.4%
$75 to $100	$0.36	1.4%	$0.23	0.8%
$100 to $125	$0.15	0.4%	$0.10	0.3%
$125 to $150	$0.04	0.1%	$0.00	0.1%
>= $150	$0.09	0.2%	$0.15	0.2%

Table 3-62 Average real-time markup component (By price category, adjusted): January 1 through September 30, 2016 and 2017

	2016 (Jan-Sep)		2017 (Jan-Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$0.06	59.6%	$0.72	49.1%
$25 to $50	$0.82	34.6%	$2.48	45.2%
$50 to $75	$0.76	3.7%	$1.07	4.4%
$75 to $100	$0.45	1.4%	$0.26	0.8%
$100 to $125	$0.17	0.4%	$0.12	0.3%
$125 to $150	$0.05	0.1%	$0.01	0.1%
>= $150	$0.11	0.2%	$0.15	0.2%

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 3-63. INC, DEC and up to congestion transactions have zero markups. INCs were 5.5 percent of marginal resources and DECs were 10.1 percent of marginal resources in the first nine months of 2017. The share 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. However, the share of marginal up to congestion transactions increased from 76.5 percent in the first nine months of 2015 to 81.9 percent in the first nine months of 2016 due to the expiration of the fifteen months resettlement period for the proceeding related to uplift charges for UTC transactions. The share of marginal up to congestion transactions decreased from 81.9 percent in the first nine months of 2016 to 80.4 percent in the first nine months of 2017. The adjusted markup of coal, gas and oil units is calculated as the difference between the price offer, and the cost offer excluding the 10 percent adder. Table 3-63 shows the markup component of LMP for marginal generating resources. Generating resources were only 4.0 percent of marginal resources in the first nine months of 2017. Using adjusted offers, the markup component of LMP for marginal generating resources increased for coal-fired steam units from $0.04 to $0.87 and increased for gas-fired CT units from $0.05 to $0.08. The markup component of LMP for coal-fired steam units increased from -$1.35 in the first nine months of 2016 to $0.15 in the first nine months of 2017 using unadjusted offers. The markup component of LMP for gas-fired steam units increased from $0.24 in the first nine months of 2016 to $0.47 in the first nine months of 2017 using unadjusted offers.

Table 3-63 Markup component of the annual PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January 1 through September 30, 2016 and 2017

		2016 (Jan - Sep)		2017 (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	($1.35)	$0.04	$0.15	$0.87
Gas	CT	$0.03	$0.05	$0.04	$0.08
Gas	Diesel	$0.00	$0.00	$0.00	$0.00
Gas	Steam	$0.24	$0.53	$0.47	$1.00
Oil	CT	$0.00	$0.00	($0.00)	$0.00
Oil	Diesel	$0.00	$0.00	$0.00	($0.00)
Oil	Steam	$0.00	$0.00	$0.00	$0.00
Other	Steam	($0.15)	($0.15)	$0.01	$0.01
Wind	Wind	$0.01	$0.01	$0.01	$0.01
Total		($1.22)	$0.48	$0.68	$1.97

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 3-64 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted offers. In the first nine months of 2017, when using unadjusted cost-based offers, $0.68 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first nine months of 2017, the peak markup component was highest in September, $2.72 per MWh using unadjusted cost offers.

Table 3-64 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January 1 through September 30, 2016 and 2017

	2016			2017		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	($2.04)	($1.71)	($2.33)	($0.03)	$0.19	($0.23)
Feb	($1.15)	($1.32)	($0.96)	$0.25	$0.59	($0.10)
Mar	($1.66)	($1.26)	($2.12)	$0.38	$0.83	($0.12)
Apr	($0.37)	$0.76	($1.54)	$0.82	$1.64	$0.03
May	($0.71)	($0.16)	($1.26)	$0.45	$1.07	($0.25)
Jun	$0.19	$0.74	($0.48)	$0.90	$1.35	$0.35
Jul	($3.73)	($6.42)	($1.05)	$0.60	$1.12	$0.09
Aug	($0.05)	$0.08	($0.22)	$1.13	$1.94	$0.09
Sep	($0.99)	($0.57)	($1.47)	$1.65	$2.72	$0.57
Oct	$0.65	$1.75	($0.45)			
Nov	$0.08	$0.52	($0.37)			
Dec	$0.30	$0.89	($0.27)			
Annual	($1.22)	($1.17)	($1.27)	$0.68	$1.27	$0.05

Table 3-65 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 2017, when using adjusted cost-based offers, $1.97 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first nine months of 2017, the peak markup component was highest in September, $3.99 per MWh using adjusted cost offers.

Table 3-65 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: January 1, 2016 through September 30, 2017

	2016			2017		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	($0.17)	$0.19	($0.48)	$1.40	$1.49	$1.32
Feb	$0.44	$0.27	$0.62	$1.65	$1.89	$1.39
Mar	($0.26)	$0.14	($0.72)	$1.65	$1.99	$1.27
Apr	$0.92	$1.86	($0.05)	$1.94	$2.50	$1.41
May	$0.60	$1.10	$0.09	$1.62	$2.05	$1.14
Jun	$1.58	$2.16	$0.89	$2.40	$2.96	$1.71
Jul	($2.90)	($6.38)	$0.58	$1.73	$1.96	$1.50
Aug	$3.94	$6.08	$1.27	$2.40	$3.09	$1.52
Sep	$0.17	$0.17	$0.16	$2.98	$3.99	$1.96
Oct	$1.69	$2.46	$0.91			
Nov	$1.25	$1.51	$0.99			
Dec	$1.82	$2.14	$1.50			
Annual	$0.48	$0.67	$0.28	$1.97	$2.44	$1.47

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 3-66. The markup component of annual average day-ahead price using adjusted offers is shown for each zone in Table 3-67. Using unadjusted offers, the markup component of the average day-ahead price increased in all zones from the first nine months of 2016 to the first nine months of 2017. The smallest zonal all hours average markup component using adjusted offers for the first nine months of 2017 was in the ComEd Zone, $1.70 per MWh, while the highest was in the AECO Control Zone, $2.39 per MWh. The smallest zonal on peak average markup using adjusted offers was in the ComEd Control Zone, $2.02 per MWh, while the highest was in the Met-Ed Control Zone, $3.01 per MWh.

Table 3-66 Day-ahead, average, zonal markup component (Unadjusted): January 1 through September 30, 2016 and 2017

	2016 (Jan - Sep)			2017 (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	($0.58)	($0.80)	($0.34)	$1.08	$1.78	$0.34
AEP	($1.81)	($2.16)	($1.44)	$0.65	$1.30	($0.03)
APS	($1.75)	($2.30)	($1.18)	$0.60	$1.18	($0.02)
ATSI	($1.79)	($1.86)	($1.71)	$0.65	$1.25	($0.03)
BGE	($2.57)	($3.23)	($1.85)	$0.52	$1.06	($0.07)
ComEd	($0.45)	$0.31	($1.31)	$0.47	$0.90	($0.01)
DAY	($1.26)	($1.17)	($1.35)	$0.71	$1.38	($0.03)
DEOK	($0.94)	($0.54)	($1.38)	$0.79	$1.53	($0.01)
DLCO	$0.13	$1.79	($1.70)	$0.65	$1.25	($0.00)
Dominion	($1.07)	($0.64)	($1.53)	$0.62	$1.25	($0.04)
DPL	($2.90)	($5.32)	($0.31)	$0.86	$1.37	$0.31
EKPC	($0.23)	$0.86	($1.35)	$0.59	$1.14	$0.03
JCPL	($1.27)	($1.84)	($0.63)	$0.95	$1.51	$0.33
Met-Ed	($1.37)	($2.01)	($0.67)	$1.04	$1.81	$0.19
PECO	$1.21	$3.01	($0.72)	$0.90	$1.49	$0.28
PENELEC	($1.52)	($1.66)	($1.38)	$0.64	$1.23	$0.03
Pepco	($1.96)	($2.29)	($1.61)	$0.58	$1.19	($0.07)
PPL	($1.20)	($1.65)	($0.70)	$0.88	$1.48	$0.23
PSEG	($0.90)	($1.02)	($0.77)	$0.95	$1.55	$0.29
RECO	($1.77)	($2.63)	($0.76)	$1.04	$1.65	$0.34

Table 3-67 Day-ahead, average, zonal markup component (Adjusted): January 1 through September 30, 2016 and 2017

	2016 (Jan - Sep)			2017 (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	$0.88	$0.77	$1.00	$2.39	$2.98	$1.76
AEP	($0.12)	($0.33)	$0.11	$1.96	$2.49	$1.41
APS	$0.05	($0.51)	$0.64	$1.90	$2.35	$1.42
ATSI	($0.32)	($0.40)	($0.25)	$1.97	$2.46	$1.43
BGE	($0.01)	$0.09	($0.11)	$1.85	$2.26	$1.40
ComEd	$1.10	$1.89	$0.22	$1.70	$2.02	$1.34
DAY	$0.59	$0.91	$0.24	$2.05	$2.61	$1.43
DEOK	$1.13	$1.99	$0.19	$2.06	$2.67	$1.40
DLCO	$1.83	$3.75	($0.28)	$1.93	$2.39	$1.42
Dominion	$0.78	$1.44	$0.08	$1.94	$2.45	$1.42
DPL	($1.65)	($4.32)	$1.21	$2.18	$2.56	$1.77
EKPC	$1.47	$2.65	$0.25	$1.87	$2.28	$1.44
JCPL	$0.18	($0.35)	$0.78	$2.24	$2.67	$1.75
Met-Ed	($0.01)	($0.79)	$0.84	$2.34	$3.01	$1.60
PECO	$2.85	$4.85	$0.70	$2.20	$2.66	$1.71
PENELEC	($0.07)	($0.23)	$0.08	$1.91	$2.37	$1.42
Pepco	$0.48	$0.82	$0.11	$1.91	$2.40	$1.39
PPL	$0.16	($0.37)	$0.74	$2.17	$2.65	$1.65
PSEG	$0.59	$0.55	$0.64	$2.22	$2.67	$1.72
RECO	($0.36)	($1.16)	$0.58	$2.30	$2.77	$1.76

Markup by Day-Ahead Price Levels

Table 3-68 and Table 3-69 show the average markup component of LMP, 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 3-68 Average, day-ahead markup (By LMP category, unadjusted): January 1 through September 30, 2016 and 2017

	2016 (Jan - Sep)		2017 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($1.82)	50.7%	($0.36)	45.4%
$25 to $50	($0.21)	45.6%	$1.16	51.4%
$50 to $75	($11.23)	3.1%	$5.49	2.5%
$75 to $100	$2.80	0.5%	$7.58	0.4%
$100 to $125	($10.09)	0.2%	$0.07	0.1%
$125 to $150	$0.00	0.0%	($0.03)	0.0%
>= $150	$0.00	0.0%	$24.36	0.1%

Table 3-69 Average, day-ahead markup (By LMP category, adjusted): January 1 through September 30, 2016 and 2017

	2016 (Jan - Sep)		2017 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.11)	50.7%	$1.33	45.4%
$25 to $50	$1.39	45.6%	$2.71	51.4%
$50 to $75	($2.45)	3.1%	$6.97	2.5%
$75 to $100	($0.06)	0.5%	$8.65	0.4%
$100 to $125	($1.17)	0.2%	($0.01)	0.1%
$125 to $150	$0.00	0.0%	($0.03)	0.0%
>= $150	$0.00	0.0%	$29.44	0.1%

Prices

The behavior 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, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of a closed loop interface related to demand side resources or reactive power.

Real-time and day-ahead energy market load-weighted prices were 3.5 percent and 1.9 percent higher in the first nine months of 2017 than in the first nine months of 2016.

PJM real-time energy market prices increased in the first nine months of 2017 compared to the first nine months of 2016. The average LMP was 5.0 percent higher in the first nine months of 2017 than in the first nine months of 2016, $28.79 per MWh versus $27.43 per MWh. The load-weighted average LMP was 3.5 percent higher in the first nine months of 2017 than in the first nine months of 2016, $30.36 per MWh versus $29.32 per MWh.

The fuel-cost adjusted, load-weighted, average LMP in the first nine months of 2017 was 21.8 percent lower than the load-weighted, average LMP for the first nine months of 2016. If fuel and emission costs in the first nine months of 2017 had been the same as in the first nine months of 2016, holding everything else constant, the load-weighted LMP would have been lower, $23.75 per MWh instead of the observed $30.36 per MWh.

PJM day-ahead energy market prices increased in the first nine months of 2017 compared to the first nine months of 2016. The day-ahead average LMP was 3.6 percent higher in the first nine months of 2017 than in the first nine months of 2016, $28.90 per MWh versus $27.90 per MWh. The day-ahead load-weighted average LMP was 1.9 percent higher in the first nine months of 2017 than in the first nine months of 2016, $30.26 per MWh versus $29.69 per MWh.

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.[66] In

66 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) at 19–27.

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, the LMPs at some pricing nodes exceed $1,000 per MWh, the cap on the generators' offer price in the PJM market.[67]

Real-Time LMP

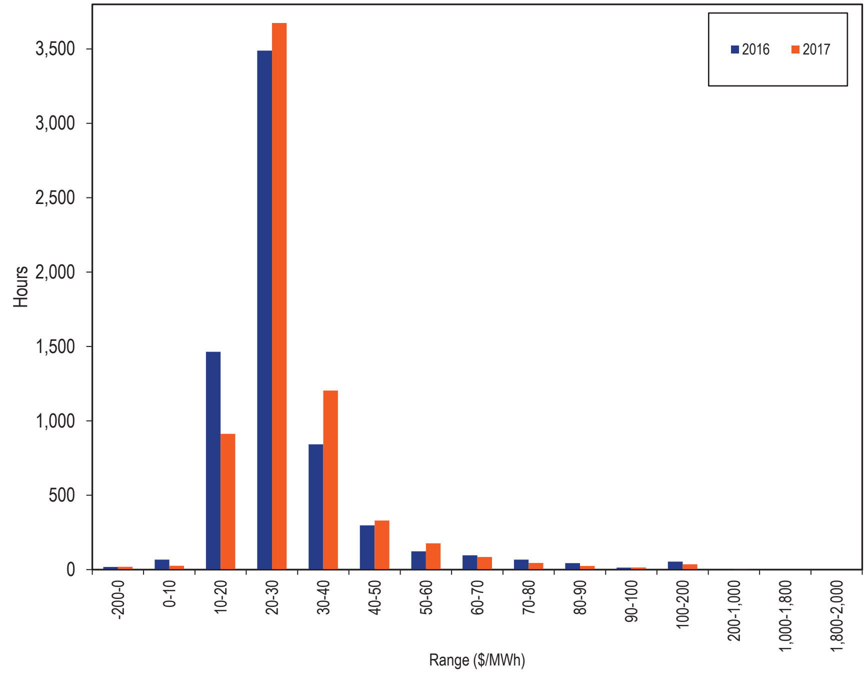
Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[68]

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 3-41 shows the hourly distribution of PJM real-time average LMP for the first nine months of 2016 and 2017.

Figure 3-41 Average LMP for the PJM Real-Time Energy Market: January 1 through September 30, 2016 and 2017



67 The offer cap in PJM was temporarily increased to $1,800 per MWh prior to the winter of 2014/2015. A new cap of $2,000 per MWh, only for offers with costs exceeding $1,000 per MWh, went into effect on December 14, 2015. See 153 FERC ¶ 61,289 (2015).

68 See the 2010 State of the Market Report for PJM: *Technical Reference for PJM Markets*, at "Calculating Locational Marginal Price," p 16-18 for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

PJM Real-Time, Average LMP

Table 3-70 shows the PJM real-time, average LMP for the first nine months of each year from 1998 through 2017.[69]

Table 3-70 PJM real-time, average LMP (Dollars per MWh): January 1 through September 30, 1998 through 2017

	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%)
2016	$27.43	$23.61	$15.73	(23.7%)	(15.3%)	(48.8%)
2017	$28.79	$25.28	$16.81	5.0%	7.1%	6.9%

Real-Time, Load-Weighted, Average LMP

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

PJM Real-Time, Load-Weighted, Average LMP

Table 3-71 shows the PJM real-time, load-weighted, average LMP in the first nine months of 1998 through 2017.

Table 3-71 PJM real-time, load-weighted, average LMP (Dollars per MWh): January 1 through September 30, 1998 through 2017

	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%)
2016	$29.32	$24.60	$17.13	(24.7%)	(15.4%)	(49.6%)
2017	$30.36	$26.26	$18.82	3.5%	6.7%	9.8%

Table 3-72 shows zonal real-time, and real-time, load-weighted, average LMP in the first nine months of 2016 and 2017.

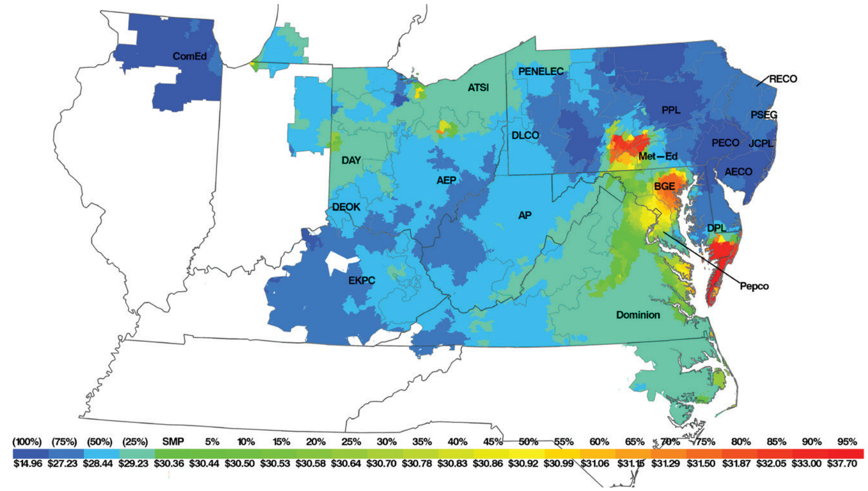
69 The system average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

Table 3-72 Zone real-time and real-time, load-weighted, average LMP (Dollars per MWh): January 1 through September 30, 2016 and 2017

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2016 (Jan-Sep)	2017 (Jan-Sep)	Percent Change	2016 (Jan-Sep)	2017 (Jan-Sep)	Percent Change
AECO	$24.55	$26.58	8.3%	$27.41	$28.38	3.5%
AEP	$27.57	$28.89	4.8%	$29.06	$30.15	3.7%
AP	$28.09	$29.12	3.7%	$29.79	$30.56	2.6%
ATSI	$28.07	$29.71	5.8%	$29.91	$31.19	4.3%
BGE	$36.35	$31.64	(12.9%)	$39.31	$33.73	(14.2%)
ComEd	$25.71	$26.95	4.8%	$27.61	$28.64	3.7%
Day	$27.65	$29.58	7.0%	$29.31	$31.14	6.2%
DEOK	$26.94	$28.99	7.6%	$28.67	$30.68	7.0%
DLCO	$27.41	$29.03	5.9%	$29.39	$30.58	4.1%
Dominion	$30.04	$30.35	1.0%	$32.22	$32.19	(0.1%)
DPL	$27.24	$28.06	3.0%	$30.57	$30.36	(0.7%)
EKPC	$26.44	$27.87	5.4%	$27.98	$29.25	4.5%
JCPL	$23.75	$27.35	15.2%	$26.63	$29.72	11.6%
Met-Ed	$23.95	$28.33	18.3%	$26.08	$30.32	16.2%
PECO	$23.44	$26.70	13.9%	$25.76	$28.42	10.3%
PENELEC	$26.20	$28.10	7.3%	$27.62	$29.28	6.0%
Pepco	$32.05	$30.76	(4.0%)	$34.30	$32.63	(4.9%)
PPL	$23.57	$27.15	15.2%	$25.37	$28.85	13.7%
PSEG	$23.99	$27.50	14.6%	$26.28	$29.38	11.8%
RECO	$24.13	$27.69	14.7%	$27.07	$30.02	10.9%
PJM	$27.43	$28.79	5.0%	$29.32	$30.36	3.5%

Figure 3-42 is a contour map of the real-time, load-weighted, average LMP in the first nine months of 2017. In the legend, green represents the system marginal price (SMP) and each increment to the right and left of the SMP represents five percent of the pricing nodes above and below the SMP. The LMP for each five percent increment is the highest nodal average LMP for that set of nodes. Each increment to the left of the SMP is the lowest nodal average LMP for that set of nodes.

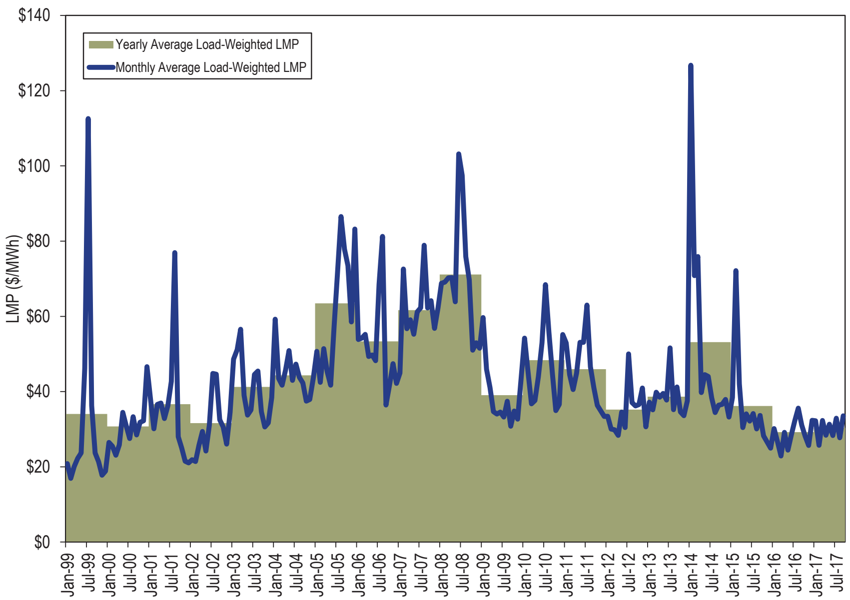
Figure 3-42 PJM real-time, load-weighted, average LMP: January 1 through September 30, 2017



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

Figure 3-43 shows the PJM real-time monthly and annual load-weighted LMP in 1999 through the first nine months of 2017. PJM real-time monthly load-weighted average LMP in June 2016 was $22.90, which is the lowest real-time monthly load-weighted average LMP since February 2002 at $21.39.

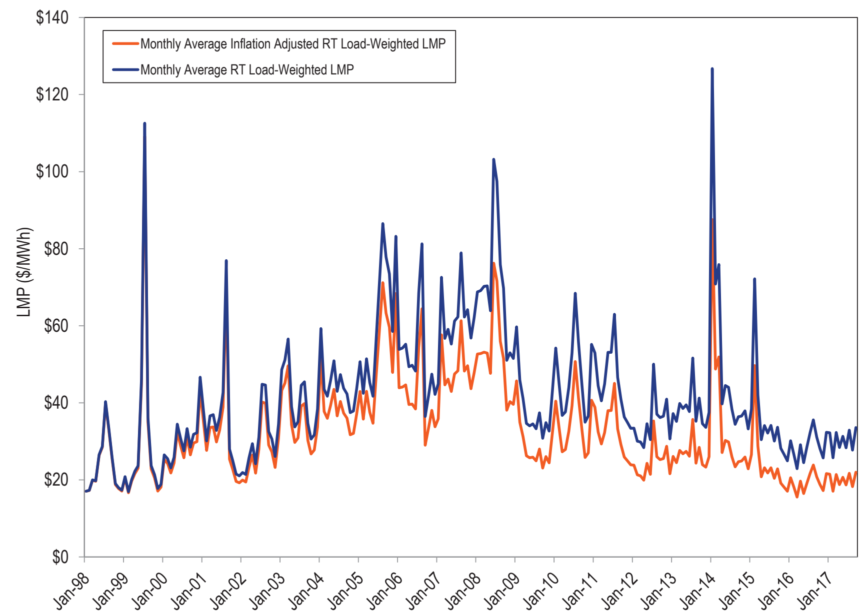
Figure 3-43 PJM real-time, monthly and annual, load-weighted, average LMP: January 1, 1999 through September 30, 2017



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

Figure 3-44 shows the PJM real-time monthly load-weighted average LMP and inflation adjusted monthly load-weighted average LMP for January 1, 1998, through September 30, 2017.[70] Table 3-73 shows the PJM real-time yearly load-weighted average LMP and inflation adjusted yearly load-weighted average LMP for the first nine months of every year starting from 1998 through 2017.

Figure 3-44 PJM real-time, monthly, load-weighted, average LMP and real-time, monthly inflation adjusted load-weighted, average LMP: January 1, 1998 through September 30, 2017



70 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using the US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed October 16, 2017)

Table 3-73 PJM real-time, yearly, load-weighted, average LMP and real-time, yearly inflation adjusted load-weighted, average LMP: January 1 through September 30, 1998 through 2017

Jan-Sep	Load-Weighted, Average LMP	Inflation Adjusted Load-Weighted, Average LMP
1998	$26.06	$25.86
1999	$38.65	$37.55
2000	$28.49	$26.82
2001	$40.96	$37.39
2002	$31.95	$28.72
2003	$43.57	$38.33
2004	$46.44	$39.85
2005	$60.44	$50.09
2006	$56.39	$45.16
2007	$61.83	$48.36
2008	$77.27	$57.70
2009	$39.57	$29.93
2010	$49.91	$37.04
2011	$49.48	$35.59
2012	$35.02	$24.68
2013	$39.75	$27.58
2014	$58.60	$40.11
2015	$38.94	$26.60
2016	$29.32	$19.77
2017	$30.36	$20.05

Fuel Price Trends and LMP

Changes in LMP can result from changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of marginal cost depending on generating technology, unit efficiency, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs. Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. Natural gas prices and coal prices increased in the first nine months of 2017 compared to the first nine months of 2016. The price of Northern Appalachian coal was 25.4 percent higher; the price of Central Appalachian coal was 33.2 percent higher; the price of Powder River Basin coal was 17.1 percent higher; the price of eastern natural gas was 35.9 percent higher; and the price of western natural gas was 37.0 percent higher. Figure 3-45 shows monthly average spot fuel prices.[71]

Figure 3-45 Spot average fuel price comparison with fuel delivery charges: January 1, 2012 through September 30, 2017 ($/MMBtu)

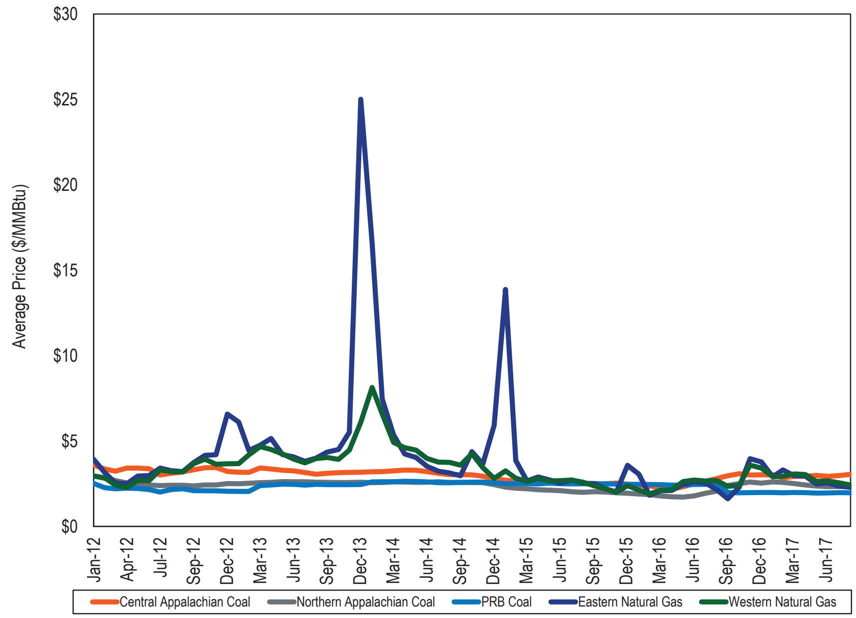


Table 3-74 compares the 2017 PJM real-time fuel-cost adjusted, load-weighted, average LMP to 2017 load-weighted, average LMP.[72] The real-time fuel-cost adjusted, load-weighted, average LMP for the first nine months of 2017 was 21.8 percent lower than the real-time load-weighted, average LMP for the first nine months of 2017. The real-time, fuel-cost adjusted, load-weighted, average LMP for the first nine months of 2017 was 19.0 percent lower than the real-time load-weighted LMP for the first nine months of 2016. If fuel and emissions costs in the first nine months of 2017 had been the same as in

71 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.

72 The fuel-cost adjusted LMP reflects both the fuel and emissions where applicable, including NO_x, CO_2 and SO_x, costs.

the first nine months of 2016, holding everything else constant, the real-time load-weighted LMP in the first nine months of 2017 would have been lower, \$23.75 per MWh, than the observed \$30.36 per MWh.

Table 3-74 PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): January 1 through September 30, 2016 and 2017

	2017 Load-Weighted LMP	2017 Fuel-Cost Adjusted, Load-Weighted LMP	Change
Average	\$30.36	\$23.75	(21.8%)
	2016 Load-Weighted LMP	2017 Fuel-Cost Adjusted, Load-Weighted LMP	Change
Average	\$29.32	\$23.75	(19.0%)
	2016 Load-Weighted LMP	2017 Load-Weighted LMP	Change
Average	\$29.32	\$30.36	3.5%

Table 3-75 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 2017. Table 3-75 shows that higher natural gas prices and coal prices explains most of the fuel-cost related increase in the real-time annual load-weighted average LMP in the first nine months of 2017.

Table 3-75 Change in PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh) by fuel type: January 1 through September 30, 2016 and 2017

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Coal	\$2.78	42.0%
Gas	\$3.73	56.4%
Municipal Waste	\$0.01	0.2%
Oil	\$0.08	1.2%
Other	\$0.00	0.0%
Uranium	(\$0.00)	-0.0%
Wind	(\$0.00)	-0.0%
Total	\$6.61	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.[73] 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 of scarcity 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 will contribute 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, January 7 of 2014 and September 21 of 2017.[74] 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.

LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission penalty factors. The shadow price directly affects the LMP. Transmission

73 New Jersey withdrew from RGGI, effective January 1, 2012.
74 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 a RTO-wide shortage of synchronized reserve. PJM triggered shortage pricing on September 21, 2017 due to a sudden decrease in imports from neighboring regions.

penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing.

Table 3-78 shows the frequency and average shadow price of transmission constraints in PJM. In the first nine months of 2017, there were 159,081 transmission constraints in the real-time market with a non-zero shadow price. For nearly seven percent of these transmission constraints, the line limit was violated, meaning that the flow exceeded the facility limit.[75] In the first nine months of 2017, the average shadow price of transmission constraints when the line limit was violated was nearly five times higher than when transmission constraint was binding at its limit.

Transmission penalty factors should be stated explicitly and publicly and applied without discretion. Penalty factors should be set high enough so that they do not act to suppress prices based on available generator solutions. But rather than permit the transmission penalty factor to set the shadow price when line limits are violated, PJM uses a procedure called constraint relaxation logic to prevent the penalty factors from directly setting the shadow price of the constraint. The result is that the transmission penalty factor does not directly set the shadow price. The details of PJM's logic and practice are not entirely clear. But in 2016, for all transmission constraints for which the penalty factor was greater than or equal to $2,000 per MWh, 41 percent of the constraints' shadow prices were within 10 percent of the penalty factor.

The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price.

The components of LMP are shown in Table 3-76, including markup using unadjusted cost offers.[76] Table 3-76 shows that in the first nine months of 2017, 30.4 percent of the load-weighted LMP was the result of coal costs, 38.3 percent was the result of gas costs and 2.12 percent was the result of the cost of emission allowances. Using adjusted cost offers, markup was 15.6 percent of the load-weighted LMP. 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 unexplained 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 2017, nearly 19.54 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 2017 and 2016.

75 The line limit of a facility associated with a transmission constraint is not necessarily the rated line limit. In PJM, the dispatcher has the discretion to lower the rated line limit.

76 These components are explained in the *Technical Reference for PJM Markets*, at p 27 "Calculation and Use of Generator Sensitivity/Unit Participation Factors." <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 3-76 Components of PJM real-time (Unadjusted), load-weighted, average LMP: January 1 through September 30, 2016 and 2017

	2016 (Jan-Sep)		2017 (Jan-Sep)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Gas	$7.29	24.9%	$11.61	38.3%	13.4%
Coal	$13.71	46.7%	$9.23	30.4%	(16.3%)
Markup	($0.04)	(0.1%)	$2.41	7.9%	8.1%
Ten Percent Adder	$2.43	8.3%	$2.32	7.7%	(0.6%)
VOM	$2.16	7.4%	$1.46	4.8%	(2.6%)
LPA Rounding Difference	$0.13	0.4%	$1.18	3.9%	3.4%
NA	$1.79	6.1%	$0.67	2.2%	(3.9%)
NO_x Cost	$0.47	1.6%	$0.51	1.7%	0.1%
Ancillary Service Redispatch Cost	$0.35	1.2%	$0.29	1.0%	(0.2%)
Oil	$0.31	1.0%	$0.25	0.8%	(0.2%)
Increase Generation Adder	$0.42	1.4%	$0.22	0.7%	(0.7%)
Scarcity Adder	$0.00	0.0%	$0.13	0.4%	0.4%
CO_2 Cost	$0.08	0.3%	$0.09	0.3%	0.0%
Municipal Waste	$0.05	0.2%	$0.05	0.2%	(0.0%)
Other	$0.19	0.7%	$0.04	0.1%	(0.5%)
SO_2 Cost	$0.08	0.3%	$0.04	0.1%	(0.1%)
Market-to-Market Adder	$0.01	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	(0.0%)
Constraint Violation Adder	$0.00	0.0%	$0.00	0.0%	0.0%
LPA-SCED Differential	($0.01)	(0.0%)	($0.01)	(0.0%)	0.0%
Decrease Generation Adder	($0.03)	(0.1%)	($0.02)	(0.1%)	0.0%
Wind	($0.06)	(0.2%)	($0.13)	(0.4%)	(0.2%)
Total	$29.32	100.0%	$30.36	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 3-76 and Table 3-83), markup is simply the difference between the price offer and the cost offer (unadjusted markup). In the second approach (Table 3-77 and Table 3-84), the 10 percent markup is removed from the cost offers of coal gas and oil units (adjusted markup).

The components of LMP are shown in Table 3-77, including markup using adjusted cost offers.

Table 3-77 Components of PJM real-time (Adjusted), load-weighted, average LMP: January 1 through September 30, 2016 and 2017

	2016 (Jan-Sep)		2017 (Jan-Sep)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Gas	$7.29	24.9%	$11.61	38.3%	13.4%
Coal	$13.71	46.7%	$9.23	30.4%	(16.3%)
Markup	$2.37	8.1%	$4.74	15.6%	7.5%
VOM	$2.16	7.4%	$1.46	4.8%	(2.6%)
LPA Rounding Difference	$0.13	0.4%	$1.18	3.9%	3.4%
NA	$1.79	6.1%	$0.67	2.2%	(3.9%)
NO_x Cost	$0.47	1.6%	$0.51	1.7%	0.1%
Ancillary Service Redispatch Cost	$0.35	1.2%	$0.29	1.0%	(0.2%)
Oil	$0.31	1.0%	$0.25	0.8%	(0.2%)
Increase Generation Adder	$0.42	1.4%	$0.22	0.7%	(0.7%)
Scarcity Adder	$0.00	0.0%	$0.13	0.4%	0.4%
CO_2 Cost	$0.08	0.3%	$0.09	0.3%	0.0%
Municipal Waste	$0.05	0.2%	$0.05	0.2%	(0.0%)
Other	$0.19	0.7%	$0.04	0.1%	(0.5%)
SO_2 Cost	$0.08	0.3%	$0.04	0.1%	(0.1%)
Market-to-Market Adder	$0.01	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	(0.0%)
Constraint Violation Adder	$0.00	0.0%	$0.00	0.0%	0.0%
Ten Percent Adder	$0.02	0.1%	($0.00)	(0.0%)	(0.1%)
LPA-SCED Differential	($0.01)	(0.0%)	($0.01)	(0.0%)	0.0%
Decrease Generation Adder	($0.03)	(0.1%)	($0.02)	(0.1%)	0.0%
Wind	($0.06)	(0.2%)	($0.13)	(0.4%)	(0.2%)
Total	$29.32	100.0%	$30.36	100.0%	0.0%

Table 3-78 Frequency and average shadow price of transmission constraints in PJM: January 1 through September 30, 2016 and 2017

	Frequency		Average Shadow Price	
Description	2016 (Jan-Sep)	2017 (Jan-Sep)	2016 (Jan-Sep)	2017 (Jan-Sep)
PJM Internal Violated Transmission Constraints	17,724	8,637	$610.84	$651.68
PJM Internal Binding Transmission Constraints	100,550	73,738	$135.28	$115.07
Market to Market Transmission Constraints	40,807	38,354	$272.23	$365.06
All Transmission Constraints	159,081	120,729	$223.40	$232.88

Day-Ahead LMP

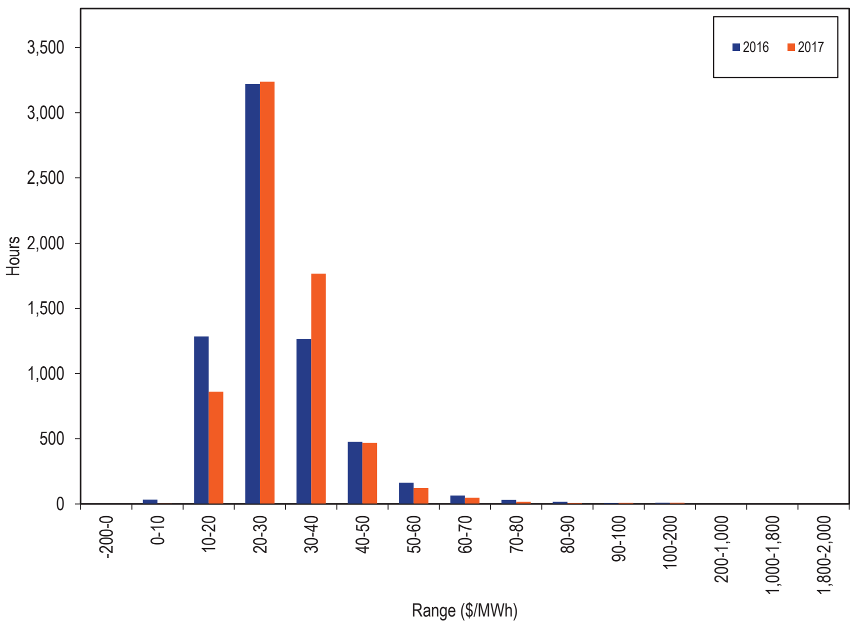
Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[77]

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-46 shows the hourly distribution of PJM day-ahead average LMP in the first nine months of 2016 and 2017.

Figure 3-46 Average LMP for the PJM Day-Ahead Energy Market: January 1 through September 30, 2016 and 2017



PJM Day-Ahead, Average LMP

Table 3-79 shows the PJM day-ahead, average LMP in the first nine months of the 17-year period 2001 through 2017.

Table 3-79 PJM day-ahead, average LMP (Dollars per MWh): January 1 through September 30, 2001 through 2017

	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%)
2016	$27.90	$25.23	$11.37	(23.9%)	(17.4%)	(54.9%)
2017	$28.90	$26.60	$10.73	3.6%	5.4%	(5.6%)

Day-Ahead, Load-Weighted, Average LMP

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

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

PJM Day-Ahead, Load-Weighted, Average LMP

Table 3-80 shows the PJM day-ahead, load-weighted, average LMP in the first nine months of the 17-year period 2001 through 2017.

Table 3-80 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January 1 through September 30, 2001 through 2017

	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%)
2016	$29.69	$26.60	$12.38	(24.8%)	(17.3%)	(55.8%)
2017	$30.26	$27.95	$11.59	1.9%	5.1%	(6.4%)

Table 3-81 shows zonal day-ahead, and day-ahead, load-weighted, average LMP in the first nine months of 2016 and 2017.

Table 3-81 Zone day-ahead and day-ahead, load-weighted, average LMP (Dollars per MWh): January 1 through September 30, 2016 and 2017

	Day-Ahead Average LMP			Day-Ahead, Load-Weighted, Average LMP		
Zone	2016 (Jan-Sep)	2017 (Jan-Sep)	Percent Change	2016 (Jan-Sep)	2017 (Jan-Sep)	Percent Change
AECO	$25.24	$26.90	6.6%	$28.16	$28.37	0.7%
AEP	$27.76	$29.05	4.6%	$29.18	$30.23	3.6%
APS	$28.57	$29.24	2.4%	$30.14	$30.47	1.1%
ATSI	$28.08	$29.63	5.5%	$29.68	$30.86	4.0%
BGE	$36.99	$31.95	(13.6%)	$40.22	$33.93	(15.6%)
ComEd	$25.88	$27.06	4.5%	$27.63	$28.50	3.2%
Day	$27.94	$29.69	6.2%	$29.43	$31.05	5.5%
DEOK	$27.45	$29.16	6.2%	$29.16	$30.70	5.3%
DLCO	$27.37	$29.05	6.2%	$29.09	$30.40	4.5%
Dominion	$30.80	$30.70	(0.3%)	$33.03	$32.49	(1.6%)
DPL	$28.89	$28.36	(1.8%)	$32.28	$30.36	(5.9%)
EKPC	$26.70	$28.24	5.8%	$28.28	$29.72	5.1%
JCPL	$24.39	$27.59	13.1%	$26.90	$29.29	8.9%
Met-Ed	$24.63	$28.31	14.9%	$26.34	$29.81	13.2%
PECO	$24.15	$26.85	11.2%	$26.29	$28.08	6.8%
PENELEC	$26.68	$28.15	5.5%	$27.87	$29.19	4.7%
Pepco	$32.90	$31.16	(5.3%)	$35.02	$32.78	(6.4%)
PPL	$24.21	$27.27	12.6%	$25.74	$28.54	10.9%
PSEG	$24.94	$27.90	11.9%	$27.14	$29.43	8.4%
RECO	$24.91	$28.04	12.6%	$27.47	$29.76	8.4%
PJM	$27.90	$28.90	3.6%	$29.69	$30.26	1.9%

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

Figure 3-47 shows the PJM day-ahead, monthly and annual, load-weighted LMP from June 2000 through September 2017.[78] The PJM day-ahead monthly load-weighted average LMP in May 2016 was $24.32, which is the lowest day-ahead monthly load-weighted average since May 2002 at $23.74.

78 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.

Figure 3-47 Day-ahead, monthly and annual, load-weighted, average LMP: June 1, 2000 through September 30, 2017

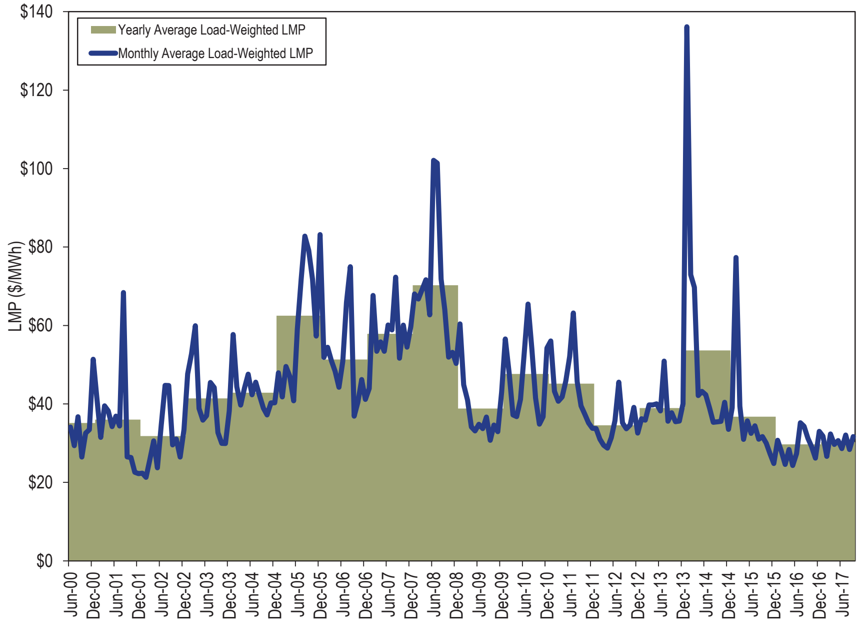
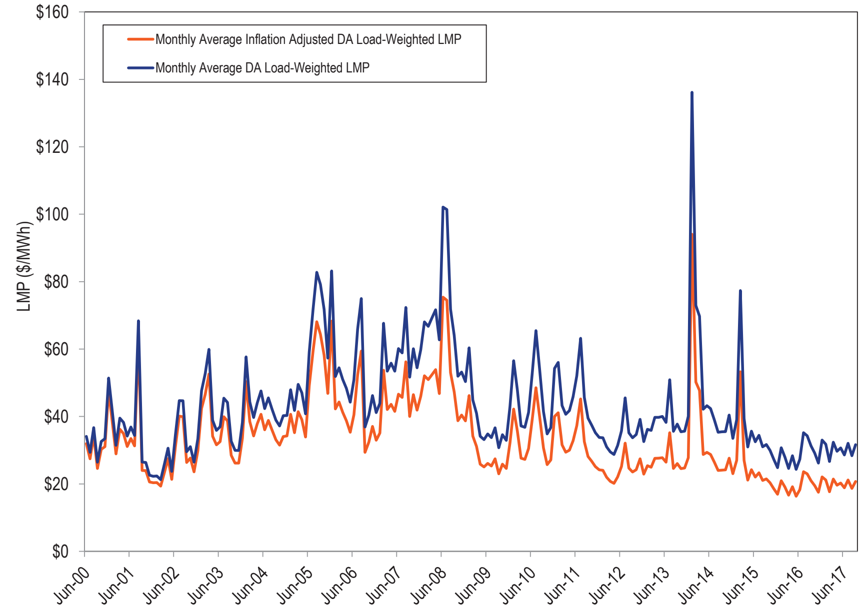


Figure 3-48 PJM day-ahead, monthly, load-weighted, average LMP and day-ahead, monthly inflation adjusted load-weighted, average LMP: June 1, 2000 through September 30, 2017



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

Figure 3-50 shows the PJM day-ahead monthly load-weighted average LMP and inflation adjusted monthly day-ahead load-weighted average LMP for June 2000 through September 2017.[79] The PJM day-ahead inflation adjusted monthly load-weighted average LMP in May 2016 was $16.36, which is the lowest day-ahead monthly load-weighted average real LMP observed since PJM day-ahead markets started in 2000. Table 3-82 shows the PJM day-ahead yearly load- weighted average LMP and inflation adjusted yearly load-weighted average LMP for the first nine months of every year from 2000 through 2017.

79 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed October 16, 2017).

Table 3-82 PJM day-ahead, yearly, load-weighted, average LMP and day-ahead, yearly inflation adjusted load-weighted, average LMP: January 1 through September 30, 2000 through 2017

Jan-Sep	Load-Weighted, Average LMP	Inflation Adjusted Load-Weighted, Average LMP
2000	$31.81	$29.74
2001	$39.88	$36.41
2002	$32.29	$29.02
2003	$44.11	$38.81
2004	$44.59	$38.26
2005	$59.51	$49.32
2006	$54.19	$43.40
2007	$57.79	$45.19
2008	$75.96	$56.73
2009	$39.35	$29.77
2010	$49.12	$36.46
2011	$48.34	$34.79
2012	$34.29	$24.17
2013	$39.49	$27.40
2014	$59.09	$40.45
2015	$39.51	$26.99
2016	$29.69	$20.03
2017	$30.26	$19.99

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, day-ahead scheduling reserve (DASR) adder and the 10 percent cost offer adder. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the Day-Ahead 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.[80] Day-ahead scheduling reserve (DASR), lost opportunity cost (LOC) and DASR offer adders are the calculated contribution to LMP when redispatch of resources is needed in order to satisfy DASR requirements.

Table 3-83 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In the first nine months of 2017, 21.2 percent of the load-weighted LMP was the result of coal costs, 18.2 percent of the load-weighted LMP was the result of gas costs, 3.0 percent was the result of the up to congestion transaction costs, 23.1 percent was the result of DEC bid costs and 23.2 percent was the result of INC bid costs.

Table 3-83 Components of PJM day-ahead, (unadjusted), load-weighted, average LMP (Dollars per MWh): January 1 through September 30, 2016 and 2017

	2016 (Jan - Sep)		2017 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
INC	($1.10)	(3.7%)	$7.01	23.2%	26.9%
DEC	$7.83	26.4%	$6.99	23.1%	(3.3%)
Coal	$12.02	40.5%	$6.40	21.2%	(19.3%)
Gas	$2.81	9.5%	$5.49	18.2%	8.7%
Ten Percent Cost Adder	$1.72	5.8%	$1.32	4.4%	(1.4%)
Up to Congestion Transaction	$0.55	1.9%	$0.92	3.0%	1.2%
VOM	$1.39	4.7%	$0.87	2.9%	(1.8%)
Markup	($1.22)	(4.1%)	$0.68	2.2%	6.3%
NO_x	$0.34	1.2%	$0.34	1.1%	(0.0%)
DASR LOC Adder	$2.69	9.1%	$0.08	0.3%	(8.8%)
CO_2	$0.37	1.3%	$0.06	0.2%	(1.1%)
Dispatchable Transaction	$2.02	6.8%	$0.04	0.1%	(6.7%)
SO_2	$0.06	0.2%	$0.03	0.1%	(0.1%)
Oil	$0.03	0.1%	$0.01	0.0%	(0.1%)
DASR Offer Adder	($0.03)	(0.1%)	$0.01	0.0%	0.1%
Other	$0.16	0.5%	$0.01	0.0%	(0.5%)
Constrained Off	$0.00	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Wind	($0.01)	(0.0%)	($0.01)	(0.0%)	0.0%
Price Sensitive Demand	$0.04	0.1%	$0.00	0.0%	(0.1%)
NA	$0.00	0.0%	$0.00	0.0%	(0.0%)
Total	$29.69	100.0%	$30.26	100.0%	0.0%

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

Table 3-84 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, gas or oil units.

Table 3-84 Components of PJM day-ahead, (adjusted), load-weighted, average LMP (Dollars per MWh): January 1 through September 30, 2016 and 2017

	2016 (Jan - Sep)		2017 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
INC	($1.10)	(3.7%)	$7.01	23.2%	26.9%
DEC	$7.83	26.4%	$6.99	23.1%	(3.3%)
Coal	$12.02	40.5%	$6.40	21.2%	(19.3%)
Gas	$2.81	9.5%	$5.49	18.2%	8.7%
Markup	$0.48	1.6%	$1.97	6.5%	4.9%
Up to Congestion Transaction	$0.55	1.9%	$0.92	3.0%	1.2%
VOM	$1.39	4.7%	$0.87	2.9%	(1.8%)
NO_x	$0.34	1.2%	$0.34	1.1%	(0.0%)
DASR LOC Adder	$2.69	9.1%	$0.08	0.3%	(8.8%)
CO_2	$0.37	1.3%	$0.06	0.2%	(1.1%)
Dispatchable Transaction	$2.02	6.8%	$0.04	0.1%	(6.7%)
SO_2	$0.06	0.2%	$0.03	0.1%	(0.1%)
Ten Percent Cost Adder	$0.02	0.1%	$0.03	0.1%	0.0%
Oil	$0.03	0.1%	$0.01	0.0%	(0.1%)
DASR Offer Adder	($0.03)	(0.1%)	$0.01	0.0%	0.1%
Other	$0.16	0.5%	$0.01	0.0%	(0.5%)
Constrained Off	$0.00	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Wind	($0.01)	(0.0%)	($0.01)	(0.0%)	0.0%
Price Sensitive Demand	$0.04	0.1%	$0.00	0.0%	(0.1%)
NA	$0.00	0.0%	$0.00	0.0%	(0.0%)
Total	$29.69	100.0%	$30.26	100.0%	0.0%

Price Convergence

The introduction of the PJM Day-Ahead Energy Market with virtuals as part of the design created the possibility that competition, exercised through the use of virtual offers and bids, could tend to cause prices in the Day-Ahead and Real-Time Energy Markets to converge more than would be the case without virtuals. 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, reactions by market participants may lead to more efficient market outcomes 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 regardless of the volume of those transactions. This is termed false arbitrage.

INCs, DECs and UTCs allow participants to profit from 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.

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.

Table 3-85 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 2016 and 2017. In the first nine months of 2017, 53.6 percent of all cleared UTC transactions were net profitable. Of cleared UTC transactions, 63.3 percent were profitable on the source side and 37.5 were profitable on the sink side but only 4.9 percent were profitable on both the source and sink side.

Table 3-85 Cleared UTC profitability by source and sink point: January 1 through September 30, 2016 and 2017[81]

Jan-Sep	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	Profitable UTC	Profitable Source	Profitable Sink
2016	15,685,907	7,421,938	10,032,684	5,491,915	47.3%	64.0%	35.0%
2017	14,588,801	7,824,106	9,236,774	5,465,683	53.6%	63.3%	37.5%

Figure 3-49 shows total UTC daily gross profits and losses and net profits and losses in the first nine months of 2017.

Figure 3-49 UTC daily gross profits and losses and net profits: January 1 through September 30, 2017[82]

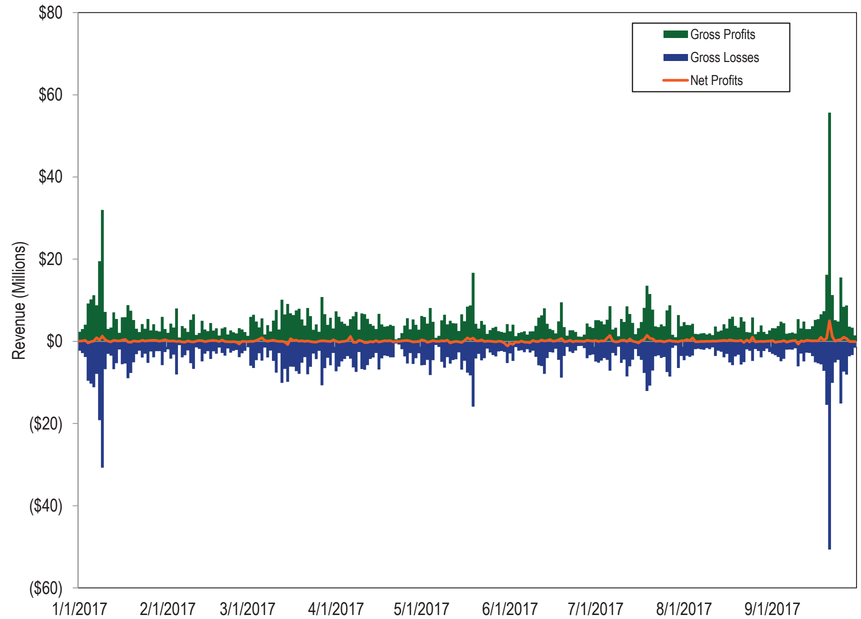


Figure 3-50 shows the cumulative UTC daily profits for the years 2013 through 2017. UTC profits during this period were primarily a result of significant unanticipated price differences between day ahead and real time LMPs. The large increases in cumulative daily UTC profits were due to PJM events that resulted in high real time LMPs. For example, the cumulative daily UTC profits in 2014 were greater than for the other three years as a result of profits from the significant and unanticipated day-ahead and real-time price differences that resulted from the polar vortex conditions in January 2014. The cumulative daily UTC profits increased during late February 2015 as a result of profits from the significant day-ahead and real-time prices differences that resulted from cold weather conditions. The cumulative daily UTC profits increased during late September 2017 as a result of profits from the significant day-

81 Calculations exclude PJM administrative charges.

82 Calculations exclude PJM administrative charges.

ahead and real-time price difference that resulted from the shortage event on September 21, 2017.

Figure 3-50 Cumulative daily UTC profits: January 1, 2013 through September 30, 2017

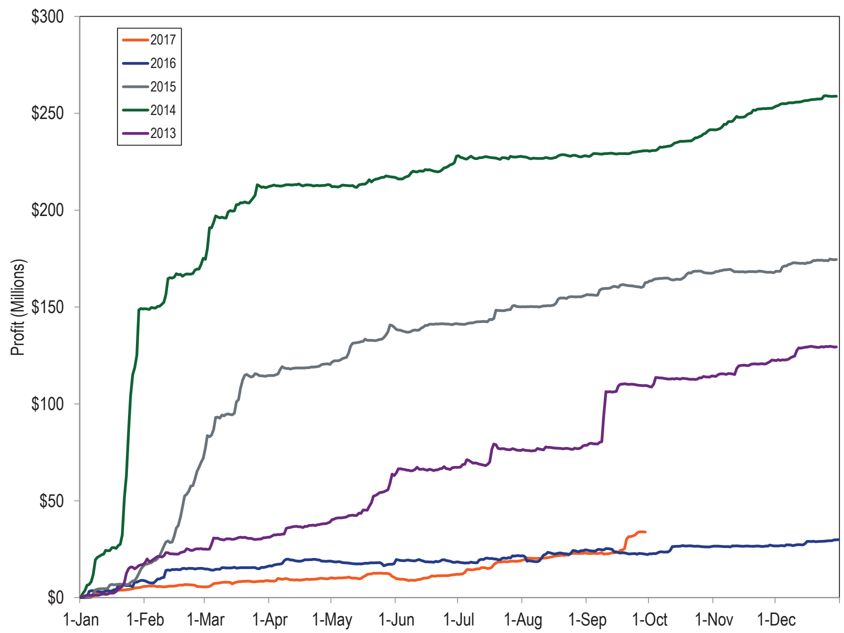


Table 3-86 UTC profits by month: January 1, 2013 through September 30, 2017

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2013	$17,048,654	$8,304,767	$5,629,392	$7,560,773	$25,219,947	$3,484,372	$8,781,526	$2,327,168	$31,160,618	$4,393,583	$8,730,701	$6,793,990	$129,435,490
2014	$148,973,434	$23,235,621	$39,448,716	$1,581,786	$3,851,636	$7,353,460	$3,179,356	$287,824	$2,727,763	$10,889,817	$11,042,443	$6,191,101	$258,762,955
2015	$16,132,319	$53,830,098	$44,309,656	$6,392,939	$19,793,475	$824,817	$8,879,275	$5,507,608	$6,957,012	$4,852,454	$392,876	$6,620,581	$174,493,110
2016	$8,874,363	$6,118,477	$1,119,457	$2,768,591	($1,333,563)	$841,706	$3,128,346	$3,200,573	($2,518,408)	$4,216,717	$254,684	$3,271,368	$29,942,312
2017	$5,716,757	($17,860)	$3,083,173	$944,939	$1,245,988	$868,412	$7,053,390	$4,002,063	$10,960,012				$33,856,874

Table 3-86 shows UTC profits by month for 2013 through September 2017. May 2016, September 2016 and February 2017 were the only months in the past five years where the total monthly profits were negative.

There are incentives to use virtual transactions to profit from 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 3-52).

Analysis of the data from September 1, 2013, through September 30, 2015, does not support the conclusion that UTCs contribute in any measurable way to price convergence. In addition, the sudden and significant reduction in UTC activity in September of 2014 did not cause a measurable change in price convergence.

Table 3-87 shows that the difference between the average real-time price and the average day-ahead price was -$0.47 per MWh in the first nine months of 2016, and -$0.11 per MWh in the first nine months of 2017. The difference between average peak real-time price and the average peak day-ahead price was -$0.60 per MWh in the first nine months of 2016 and -$0.11 per MWh in the first nine months of 2017.

Table 3-87 Day-ahead and real-time average LMP (Dollars per MWh): January 1 through September 30, 2016 and 2017[83]

	Jan-Sep 2016				Jan-Sep 2017			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$27.90	$27.43	($0.47)	(1.7%)	$28.90	$28.79	($0.11)	(0.4%)
Median	$25.23	$23.61	($1.62)	(6.9%)	$26.60	$25.28	($1.31)	(5.2%)
Standard deviation	$11.37	$15.73	$4.36	27.7%	$10.73	$16.81	$6.08	36.2%
Peak average	$33.48	$32.88	($0.60)	(1.8%)	$34.01	$33.90	($0.11)	(0.3%)
Peak median	$29.92	$26.87	($3.04)	(11.3%)	$32.00	$29.37	($2.63)	(9.0%)
Peak standard deviation	$11.91	$18.04	$6.13	34.0%	$11.67	$20.89	$9.22	44.1%
Off peak average	$23.01	$22.65	($0.36)	(1.6%)	$24.43	$24.32	($0.11)	(0.4%)
Off peak median	$21.57	$21.04	($0.53)	(2.5%)	$22.75	$22.40	($0.36)	(1.6%)
Off peak standard deviation	$8.17	$11.40	$3.23	28.3%	$7.34	$10.27	$2.93	28.6%

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 3-88 shows the difference between the real-time and the day-ahead energy market prices for the first nine months of 2001 through 2017.

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

Table 3-88 Day-ahead and real-time average LMP (Dollars per MWh): January 1 through September 30, 2001 through 2017

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%)
2016	$27.90	$27.43	($0.47)	(1.7%)
2017	$28.90	$28.79	($0.11)	(0.4%)

Table 3-89 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for the first nine months of 2007 through 2017.

Table 3-89 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): January 1 through September 30, 2007 through 2017

Jan-Sep	2007		2008		2009		2010		2011		2012		2013	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	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%
($750) to ($500)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($500) to ($450)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	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%
($400) to ($350)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($350) to ($300)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	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%
($250) to ($200)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%	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%
($150) to ($100)	0	0.00%	1	0.02%	0	0.00%	0	0.00%	2	0.05%	6	0.17%	5	0.14%
($100) to ($50)	26	0.40%	88	1.35%	3	0.05%	13	0.20%	49	0.79%	17	0.43%	9	0.27%
($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%
$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%
$50 to $100	193	99.50%	264	99.33%	34	99.97%	130	99.56%	169	99.56%	61	99.53%	58	99.62%
$100 to $150	21	99.82%	37	99.89%	2	100.00%	20	99.86%	21	99.88%	14	99.74%	12	99.80%
$150 to $200	4	99.88%	4	99.95%	0	100.00%	8	99.98%	2	99.91%	10	99.89%	10	99.95%
$200 to $250	1	99.89%	2	99.98%	0	100.00%	1	100.00%	3	99.95%	4	99.95%	1	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%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.95%	2	100.00%	0	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%
$400 to $450	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%	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%
$500 to $750	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%	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%
$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%
>= $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Jan-Sep	2014		2015		2016		2017	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($1,000) to ($750)	2	0.03%	0	0.00%	0	0.00%	0	0.00%
($750) to ($500)	3	0.08%	0	0.00%	0	0.00%	0	0.00%
($500) to ($450)	1	0.09%	0	0.00%	0	0.00%	0	0.00%
($450) to ($400)	6	0.18%	0	0.00%	0	0.00%	0	0.00%
($400) to ($350)	5	0.26%	0	0.00%	0	0.00%	0	0.00%
($350) to ($300)	5	0.34%	0	0.00%	0	0.00%	0	0.00%
($300) to ($250)	6	0.43%	0	0.00%	0	0.00%	0	0.00%
($250) to ($200)	14	0.64%	1	0.02%	0	0.00%	0	0.00%
($200) to ($150)	14	0.85%	4	0.08%	0	0.00%	0	0.00%
($150) to ($100)	45	1.54%	17	0.34%	0	0.00%	2	0.03%
($100) to ($50)	89	2.90%	65	1.33%	13	0.20%	3	0.08%
($50) to $0	4,301	68.55%	4,417	68.75%	4,299	65.58%	4,098	62.63%
$0 to $50	1,871	97.11%	1,901	97.77%	2,201	99.06%	2,414	99.48%
$50 to $100	97	98.60%	101	99.31%	49	99.80%	26	99.88%
$100 to $150	37	99.16%	33	99.82%	13	100.00%	5	99.95%
$150 to $200	18	99.44%	7	99.92%	0	100.00%	1	99.97%
$200 to $250	9	99.57%	3	99.97%	0	100.00%	0	99.97%
$250 to $300	8	99.69%	1	99.98%	0	100.00%	0	99.97%
$300 to $350	3	99.74%	1	100.00%	0	100.00%	0	99.97%
$350 to $400	3	99.79%	0	100.00%	0	100.00%	0	99.97%
$400 to $450	2	99.82%	0	100.00%	0	100.00%	1	99.98%
$450 to $500	0	99.82%	0	100.00%	0	100.00%	0	99.98%
$500 to $750	7	99.92%	0	100.00%	0	100.00%	1	100.00%
$750 to $1,000	0	99.92%	0	100.00%	0	100.00%	0	100.00%
$1,000 to $1,250	1	99.94%	0	100.00%	0	100.00%	0	100.00%
>= $1,250	4	100.00%	0	100.00%	0	100.00%	0	100.00%

Figure 3-51 shows the hourly differences between day-ahead and real-time hourly LMP in the first nine months of 2017.

Figure 3-51 Real-time hourly LMP minus day-ahead hourly LMP: January 1 through September 30, 2017

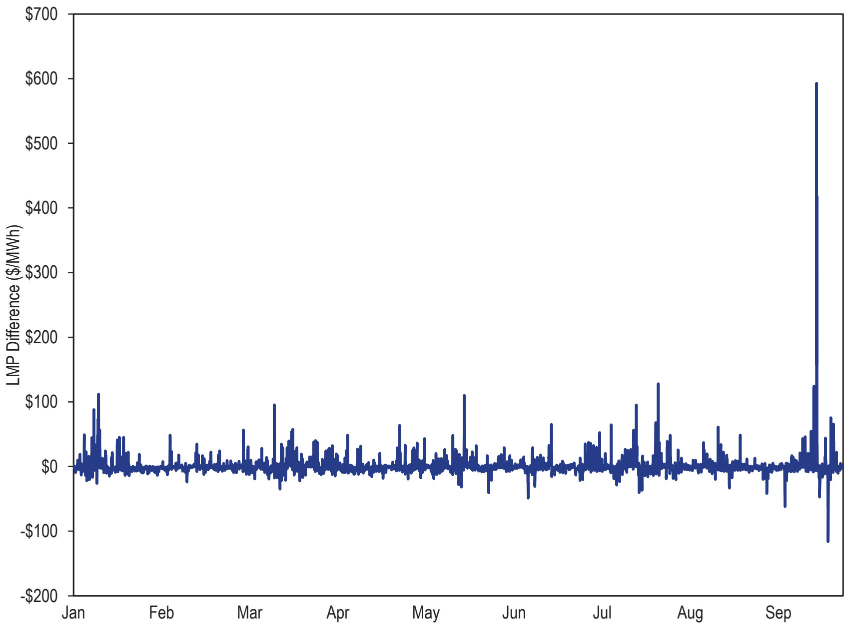


Figure 3-52 shows the monthly average of the differences between the day-ahead and real-time PJM average LMPs from January 2013, through September 2017.

Figure 3-52 Monthly average of real-time minus day-ahead LMP: January 1, 2013 through September 30, 2017

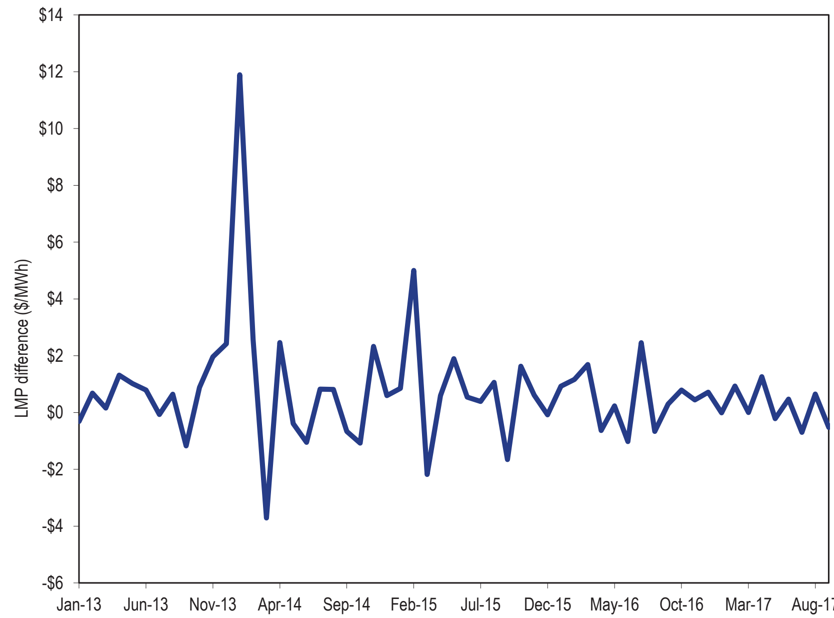


Figure 3-53 shows the monthly average of the absolute value of the differences between the day-ahead and real-time hourly, nodal LMPs from January 2013, through September 2017.

Figure 3-53 Monthly average of the absolute value of real-time minus day-ahead LMP by pnode: January 1, 2013 through September 30, 2017

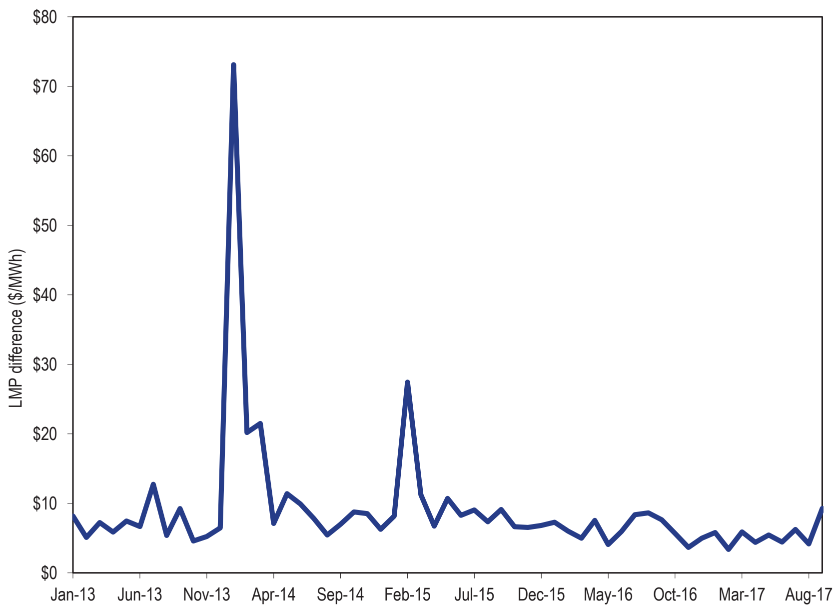
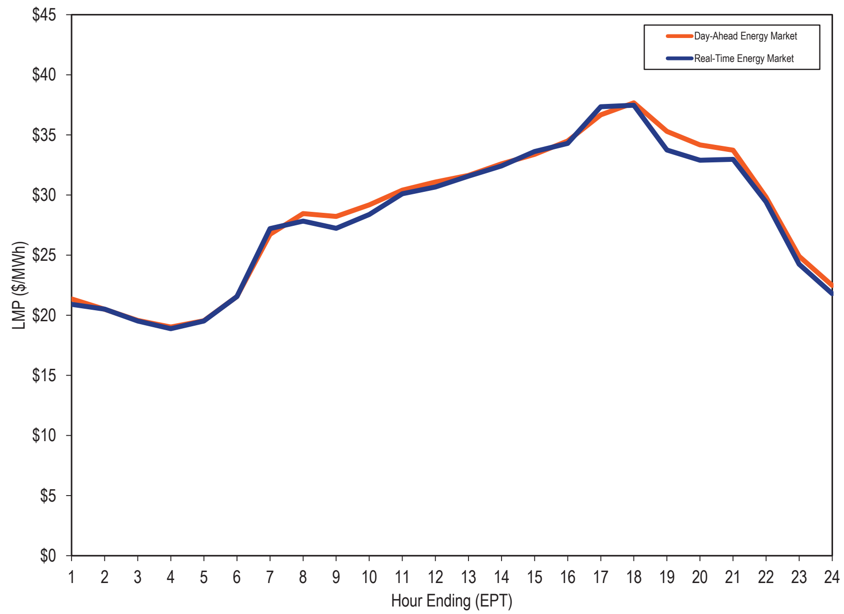


Figure 3-54 shows day-ahead and real-time LMP on an average hourly basis for the first nine months of 2017.

Figure 3-54 PJM system hourly average LMP: January 1 through September 30, 2017



Scarcity

PJM's energy market experienced shortage pricing on one day (September 21) in the first nine months of 2017. Table 3-90 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in the first nine months of 2016 and 2017.

Table 3-90 Summary of emergency events declared: January 1 through September 30, 2016 and 2017

	Number of days events declared	
Event Type	Jan - Sep, 2016	Jan - Sep, 2017
Cold Weather Alert	4	0
Hot Weather Alert	22	17
Maximum Emergency Generation Alert	0	0
Primary Reserve Alert	0	0
Voltage Reduction Alert	0	0
Primary Reserve Warning	0	0
Voltage Reduction Warning	0	0
Pre Emergency Mandatory Load Management Reduction Action	0	0
Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time)	0	0
Maximum Emergency Action	0	0
Emergency Energy Bids Requested	0	0
Voltage Reduction Action	0	0
Shortage Pricing	0	1
Energy export recalls from PJM capacity resources	0	0

Figure 3-55 shows the number of days that weather and capacity emergency alerts were issued in PJM in the first nine months of 2013 through 2017. Figure 3-56 shows the number of days emergency warnings were issued and actions were taken in PJM in the first nine months of 2013 through 2017.

Figure 3-55 PJM declared emergency alerts: January 1 through September 30, 2013 to 2017

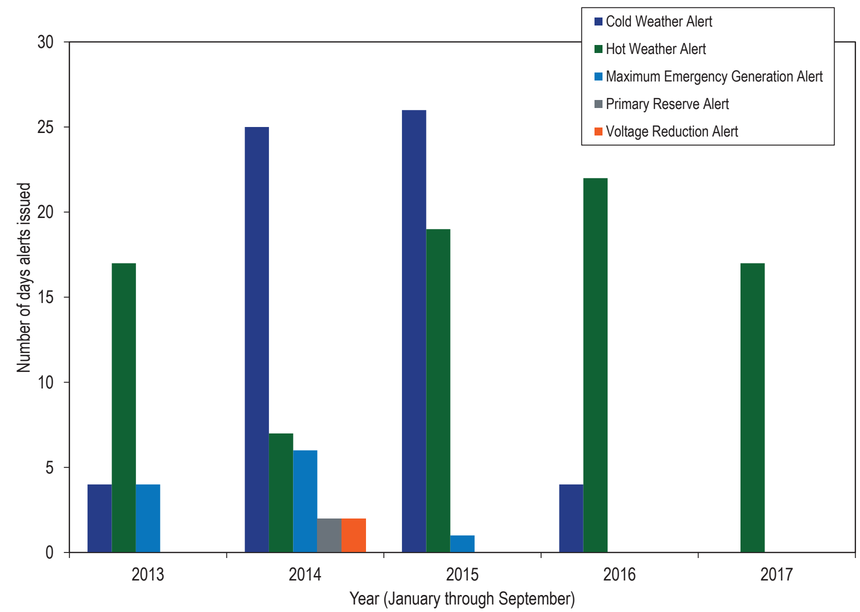
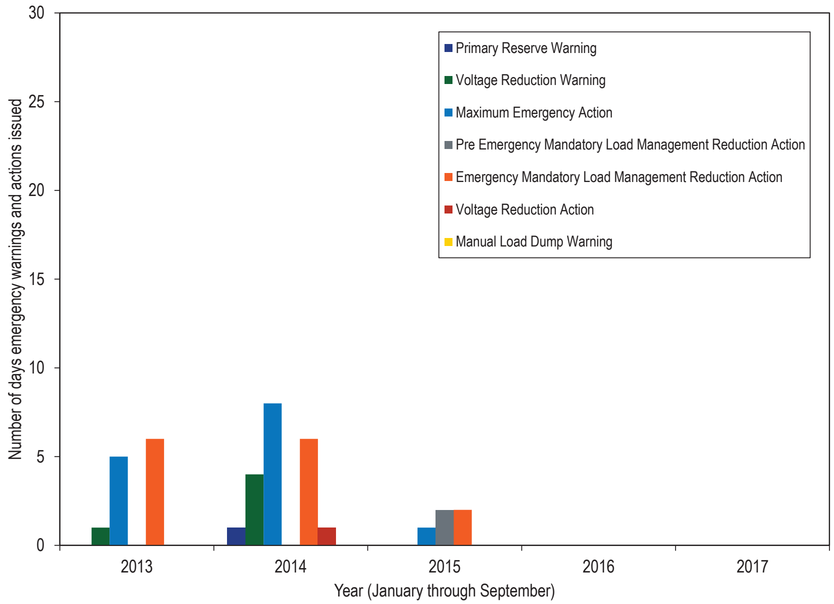


Figure 3-56 PJM declared emergency warnings and actions: January 1 through September 30, 2013 to 2017



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 did not declare any cold weather alerts in the first nine months of 2017 compared to four days in the first nine months of 2016.[84] The purpose of a cold weather alert is to prepare personnel and facilities for expected extreme cold weather conditions, generally when temperatures are forecast to approach minimums or fall below 10 degrees Fahrenheit.

84 See PJM. "Manual 13: Emergency Operations," Rev. 64 (June 1, 2017), Section 3.3 Cold Weather Alert, p. 59.

PJM declared hot weather alerts on 17 days in the first nine months of 2017 compared to 22 days in the first nine months of 2016.[85] The purpose of a hot weather alert is to prepare personnel and facilities for expected extreme hot and humid weather conditions, generally when temperatures are forecast to exceed 90 degrees Fahrenheit with high humidity.

PJM did not declare any maximum emergency generation alerts in the first nine months of 2017 and 2016. The purpose of a maximum emergency generation alert is to provide an alert at least one day prior to the operating day that system conditions may require use of PJM emergency actions. It is called to alert PJM members that maximum emergency generation may be requested in the operating capacity.[86] This means that if PJM directs members to load maximum emergency generation during the operating day, the resources must be able to increase generation above the maximum economic level of their offer.

PJM did not declare any primary reserve alerts in the first nine months of 2017 and 2016. 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 2017 and 2016. The purpose of a voltage reduction alert is to alert members at least one day prior to the operating day that a voltage reduction may be required on the operating day. It is issued when the estimated operating reserve is less than the forecast synchronized reserve requirement.

PJM did not declare any primary reserve warning in the first nine months of 2017 and 2016. 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.

85 See PJM. "Manual 13: Emergency Operations," Rev. 64 (June 1, 2017), Section 3.4 Hot Weather Alert, p. 64.
86 *Id* at 20.

PJM did not declare any voltage reduction warnings and reductions of noncritical plant load in the first nine months of 2017 and 2016. The purpose of a voltage reduction warning and reduction of noncritical 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 did not declare any emergency mandatory load management reductions in the first nine months of 2017 and 2016. 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 did not declare any maximum emergency generation actions in the first nine months of 2017 and 2016. The purpose of a maximum emergency generation action is to request generators to increase output to the maximum emergency level which unit owners may define at a level above the maximum economic level. A maximum emergency generation action can be issued for the RTO, for specific control zones or for parts of control zones.

PJM did not request any offers for emergency energy purchases in the first nine months of 2017 and 2016.

PJM did not declare any voltage reduction actions in the first nine months of 2017 and 2016. 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 subzone, the primary reserve penalty factor and synchronized reserve penalty factor are incorporated into the synchronized and nonsynchronized reserve market clearing prices and locational marginal prices until the voltage reduction action has been terminated.

PJM declared sixteen synchronized reserve events in the first nine months of 2017 compared to eleven synchronized reserve events in the first nine months of 2016.[87] 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 3-91 provides a description of PJM declared emergency procedures.

87 See *2017 Quarterly State of the Market Report for PJM: January through September*, Section 10: Ancillary Service Markets for details on the spinning events.

Table 3-91 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.
Pre-Emergency Load Management Reduction Action	To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time before declaring emergency load management reductions
Emergency Mandatory Load Management Reduction Action	To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time to provide additional load relief, generally declared simultaneously with NERC Energy Emergency Alert Level 2 (EEA2)
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.
Maximum Emergency Generation Action	To provide real time notice to increase generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the maximum economic level.
Voltage Reduction Warning & Reduction of Non-Critical Plant Load	To warn members that actual synchronized reserves are less than the synchronized reserve requirement and that voltage reduction may be required.
Deploy All Resources Action	For emergency events that do not evolve over time, but rather develop rapidly and without prior warning, PJM issues this action to instruct all generation resources to be online immediately and to all load management resources to reduce load immediately.
Manual Load Dump Warning	To warn members of the critical condition of present operations that may require manually dumping load. Issued when available primary reserve capacity is less than the largest operating generator or the loss of a transmission facility jeopardizes reliable operations after all other possible measures are taken to increase reserve.
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.
Manual Load Dump Action	To provide load relief when all other possible means of supplying internal PJM RTO load have been used to prevent a catastrophe within the PJM RTO or to maintain tie schedules so as not to jeopardize the reliability of the other interconnected regions.

Table 3-92 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in the first nine months of 2017.

Table 3-92 PJM declared emergency alerts, warnings and actions: January 1 through September 30, 2017

Date	Cold Weather Alert	Hot Weather Alert	Maximum Emergency Generation Alert	Primary Reserve Alert	Voltage Reduction Alert	Primary Reserve Warning	Voltage Reduction Warning and Reduction of Non-Critical Plant Load	Maximum Emergency Generation Action	Pre-Emergency Mandatory Load Management Reduction	Emergency Mandatory Load Management Reduction	Voltage Reduction	Manual Load Dump Warning
5/17/2017		PJM RTO										
5/18/2017		PJM RTO										
6/11/2017		PJM RTO										
6/12/2017		PJM RTO										
6/13/2017		PJM RTO										
6/30/2017		Mid Atlantic										
7/11/2017		Mid Atlantic and Dominion										
7/12/2017		PJM RTO										
7/13/2017		Mid Atlantic and Dominion										
7/14/2017		Dominion										
7/19/2017		Dominion and EKPC										
7/20/2017		PJM RTO										
7/21/2017		PJM RTO										
7/22/2017		Mid Atlantic and Dominion										
8/22/2017		Mid Atlantic and Dominion										
9/25/2017		PJM RTO										
9/26/2017		PJM RTO										

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 these 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.[88] 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 subzone. 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 nonsynchronized reserve market clearing prices and

88 See OA Schedule 1 § 2.2(d).

the locational marginal price. The market clearing prices for reserves during reserve shortages in real time were determined based on vertical demand curves for synchronized and primary reserves, defined for the Mid-Atlantic Region and for the entire RTO, called the Operating Reserve Demand Curves (ORDC). The penalty factors for the reserve products in the ORDC started at $250 per MWh for the 2012/2013 delivery year and gradually increased to $850 per MWh for the 2015/2016 delivery year.

In 2015, PJM revised the rules to add a conditional second step to the operating reserve demand curves, that would only be in effect during hot weather alerts, cold weather alerts and other emergency conditions, to allow PJM to procure additional reserves at a lower clearing price of $300 per MWh.[89] When there are no emergency conditions in place, the ORDC remained a single-step curve.

On May 11, 2017, PJM made revisions to the triggers for shortage pricing and implemented five minute shortage pricing in response to Order No. 825. These revisions did not change the operating reserve demand curves.

On July 12, 2017, PJM implemented updates to the Operating Reserve Demand Curves that determine the value of the penalty factors that are incorporated in the calculation of the synchronized and primary reserve market clearing prices and the locational marginal price for energy. PJM added an extended reserve requirement to the operating reserve demand curves. The extended synchronized reserve requirement is defined as the synchronized reserve requirement plus 190 MW. The extended primary reserve requirement is defined as the primary reserve requirement plus 190 MW. PJM retains the ability to add a conditional extended reserve requirement during hot weather alerts, cold weather alerts or other emergencies that would increase the extended reserve requirement beyond 190 MW.

In the first nine months of 2017, shortage pricing was triggered on one day in PJM.

89 151 FERC ¶ 61,017 (2015).

Final Rule on Shortage Pricing and Settlement Intervals (Order No. 825)

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").[90] In particular, the price formation NOPR proposed (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.[91]

On June 16, 2016, the Commission issued a Final Rule in which it required each RTO/ISO to settle energy, operating reserves and intertie transactions using the same time intervals that it uses for to dispatch units or schedule these transactions (Order No. 825).[92] In PJM, the energy market dispatch and pricing interval is five minutes, and the order requires PJM to settle energy transactions on a five minute basis. In PJM, the synchronized reserve and regulation market dispatch and pricing interval is five minutes, and the order requires PJM to settle these reserves on a five minute basis. In PJM, intertie transactions are scheduled on 15 minute intervals, and the order requires PJM to settle intertie transactions on a 15 minute basis. However, the Commission allowed PJM to propose a shorter time interval for settling intertie transactions.[93]

The Commission also required each RTO/ISO to trigger shortage pricing for any dispatch and pricing interval in which a shortage of energy or operating reserves is indicated by the RTO/ISO's software.[94] In PJM, the rule would require PJM to trigger shortage pricing for any five minute interval when the Real-Time SCED (Security Constrained Economic Dispatch) indicates a shortage of synchronized reserves or primary reserves. Currently in PJM, if

90 152 FERC ¶ 61,218 (2015).
91 *Id* at P 5.
92 155 FERC ¶ 61,276 (2016).
93 *Id* at P 90.
94 *Id* at P 162.

the dispatch tools (Intermediate-Term and Real-Time SCED) reflect a shortage of reserves (primary or synchronized) for a time period shorter than a defined threshold (30 minutes) 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. Currently, both Real-Time SCED and Intermediate-Term SCED have to consistently identify that a shortage of a particular reserve product exists for a period of at least 30 minutes to trigger the shortage pricing penalty factor for that reserve product. For example, if Real-Time SCED indicates a shortage of RTO wide primary reserve for an interval but the Intermediate-Term SCED forecasts that the reserve shortage does not extend beyond its first look ahead interval (15 minutes ahead of the Real-Time SCED interval), it is considered a transient shortage, and shortage pricing is not implemented. If Real-Time SCED indicates a shortage of RTO wide primary reserve for an interval and the Intermediate-Term SCED forecasts that the reserve shortage extends for at least two look ahead intervals (30 minutes ahead of the Real-Time SCED interval), shortage pricing is implemented. 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.[95]

PJM Compliance Filing on Shortage Pricing

On January 11, 2017, PJM filed proposed tariff revisions to comply with Order No. 825 and requested a simultaneous implementation date of February 1, 2018, for the settlement interval reforms and shortage pricing reforms.[96] In the January 11th Compliance Filing, PJM proposed to implement shortage pricing through the inclusion of the Reserve Penalty Factors in real-time LMPs when the real-time security constrained economic dispatch software determines that a primary reserve or synchronized reserve shortage exists on a five minute basis.

On February 1, 2017, the MMU filed comments generally supporting the January 11th Compliance Filing but seeking a number of refinements.[97] The MMU recommended that: (i) the PJM rules require that dispatchable resources have five minute meters so that there can be accurate five minute settlements; (ii) the rules clarify the settlement interval applicable to withdrawals by generators; (iii) the exemption of DR from the five minute settlements requirement be removed; (iv) the rules consistently provide for division by 12; (v) that the rules include a precise mathematical formulation of deviation charges with clear definitions of withdrawals and injections, units of measurement, and time periods; and (vi) that the rules require PJM to document biasing practices that affect market outcomes, as used in SCED (Security Constrained Economic Dispatch) and ASO (Ancillary Services Optimizer) and to report its application of biasing.[98]

On May 11, 2017, PJM implemented five minute shortage pricing. From May 11 through September 30, there were 21 intervals when five minute shortage pricing was triggered, all on the same day, September 21.

PJM Tariff Revisions to Operating Reserve Demand Curves

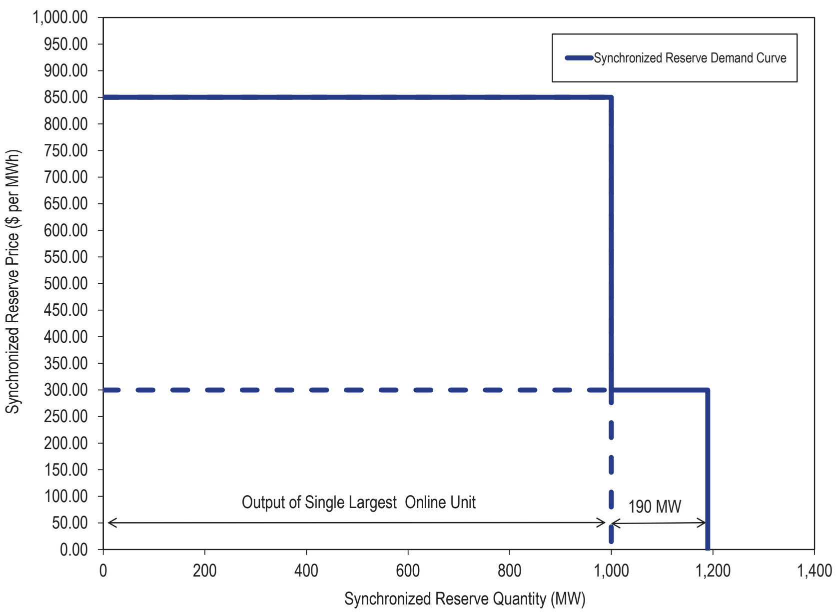
On May 12, 2017, PJM submitted tariff revisions to reflect changes to the Operating Reserve Demand Curves (ORDC) used in the Real-Time Energy Market to price shortage of primary reserves and synchronized reserves.[99] The updates to the ORDC went into effect on July 12, 2017.

PJM revised the synchronized reserve requirement in a reserve zone or a subzone from the economic maximum of the largest unit on the system to 100 percent of the actual output of the single largest online unit in that reserve zone or subzone. PJM revised the primary reserve requirement in a reserve zone or a subzone from 150 percent of the economic maximum of the largest unit on the system to 150 percent of the actual output of the single largest online unit in that reserve zone or subzone. The first step of the demand curves for primary and synchronized reserves are set at the primary and synchronized reserve requirement. Since the primary and synchronized

95 *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).
96 *See PJM Interconnection LLC*, Order No. 825 Compliance Filing, Docket No. ER17-775 (January 11, 2017) ("January 11th Compliance Filing").
97 Comments of the Independent Market Monitor for PJM, Docket No. ER17-775.
98 *Id.*
99 See PJM Filing, FERC Docket No. ER17-1590-000 (May 12, 2017).

reserve requirements are based on the actual output of the largest resource, the MW value of the first step changes in real time based on the real-time dispatch solution. The first step continues to be priced at $850 per MWh. PJM also added a permanent second step to the primary and synchronized reserve demand curves, set at the extended primary and synchronized reserve requirements. The extended primary and synchronized reserve requirements are defined as the primary and synchronized reserve requirements, plus 190 MW. This 190 MW second step is priced at $300 per MWh. Figure 3-57 shows an example of the updated synchronized reserve demand curve when the output of the single largest unit in the region equals 1,000 MW.

Figure 3-57 Updated synchronized reserve demand curve showing the permanent second step



Shortage Pricing on September 21, 2017

The MMU analyzed intervals when shortage pricing was triggered on September 21, 2017. During all 21 intervals, the quantity of reserves was greater than the Synchronized Reserve Requirement and the Primary Reserve Requirement, and therefore the $850/MWh penalty factors for violating these requirements were not incorporated in LMPs.

During the two 5 minute intervals beginning 1415 EPT and 1420 EPT, the synchronized reserves in the RTO Region were lower than the extended synchronized reserve requirement by 16.1 MW. Table 3-93 shows the RTO synchronized reserve MW and the extended synchronized reserve requirement during the period from 1415 to 1425 EPT.

Table 3-93 RTO synchronized reserve MW and extended synchronized reserve requirement during synchronized reserve shortage

Interval	RTO Extended Synchronized Reserve Requirement (MW)	RTO Total Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)
21-Sep-17 14:15	1,576.5	1,560.4	16.1
21-Sep-17 14:20	1,576.5	1,560.4	16.1

During the seven 5 minute intervals beginning 1425 EPT through 1500 EPT, and the twelve 5 minute intervals beginning 1555 EPT through 1655 EPT, the primary reserves in the RTO Region were lower than the extended primary reserve requirement. Table 3-94 shows the RTO primary reserve MW and the extended primary reserve requirement during the period from 1425 EPT through 1500 EPT and from 1555 EPT through 1655 EPT.

Table 3-94 RTO primary reserve MW and extended primary reserve requirement during primary reserve shortage

Interval	RTO Extended Primary Reserve Requirement (MW)	RTO Total Primary Reserves (MW)	RTO Primary Reserve Shortage (MW)
21-Sep-17 14:25	2,260	2,241	19
21-Sep-17 14:30	2,260	2,241	19
21-Sep-17 14:35	2,260	2,241	19
21-Sep-17 14:40	2,270	2,138	132
21-Sep-17 14:45	2,270	2,138	132
21-Sep-17 14:50	2,279	2,211	68
21-Sep-17 14:55	2,279	2,211	68
21-Sep-17 15:55	2,360	2,245	115
21-Sep-17 16:00	2,370	2,245	126
21-Sep-17 16:05	2,375	2,230	145
21-Sep-17 16:10	2,384	2,228	156
21-Sep-17 16:15	2,384	2,228	156
21-Sep-17 16:20	2,392	2,232	161
21-Sep-17 16:25	2,385	2,224	161
21-Sep-17 16:30	2,385	2,224	161
21-Sep-17 16:35	2,380	2,227	153
21-Sep-17 16:40	2,380	2,227	153
21-Sep-17 16:45	2,380	2,227	153
21-Sep-17 16:50	2,388	2,277	111

During the four 5 minute intervals beginning 1440 EPT through 1500 EPT, the primary reserves in the MAD Region were lower than the MAD extended primary reserve requirement. Table 3-95 shows the MAD primary reserve MW and the MAD extended primary reserve requirement during the period from 1440 to 1500 EPT. From 1440 EPT to 1500 EPT, the market clearing price for synchronized and primary reserves for units located in the MAD reserve zone included the $300/MWh penalty factor from the second step of the MAD primary reserve demand curve and the $300/MWh penalty factor from the second step of the RTO primary reserve demand curve.

Table 3-95 MAD primary reserve MW and extended primary reserve requirement during primary reserve shortage

Interval	MAD Extended Primary Reserve Requirement (MW)	MAD Total Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)
21-Sep-17 14:40	2,236	2,125	112
21-Sep-17 14:45	2,236	2,125	112
21-Sep-17 14:50	2,233	2,197	36
21-Sep-17 14:55	2,233	2,197	36

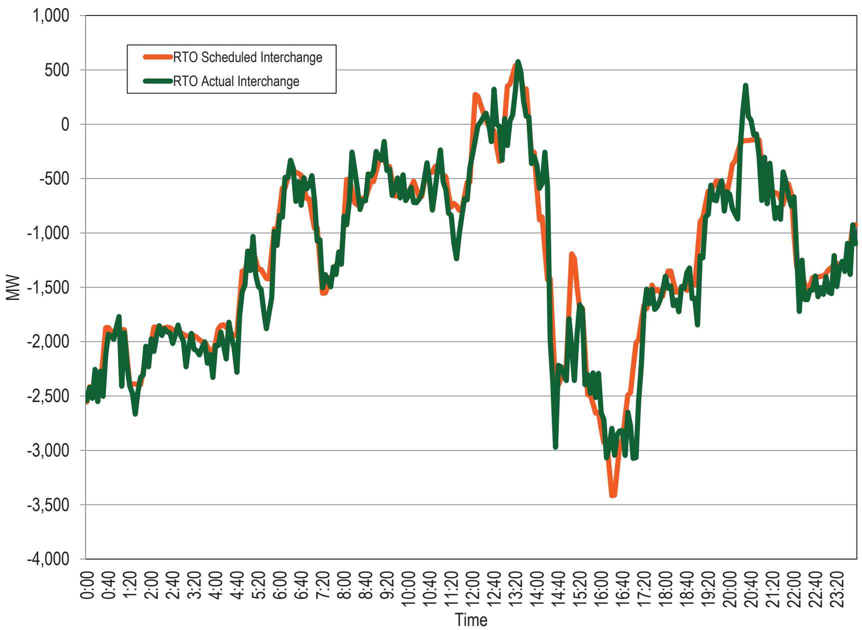
There were a number of factors that affected the periods when shortage pricing was triggered on September 21, 2017, including interchange transactions, available and scheduled generation capacity in real time, operator inputs to SCED, and the performance of regulation resources. The PJM Area Control Error (ACE) dropped by more than 1,000 MW from 1400 to 1415 and this resulted in PJM declaring a spinning event at 1415. The MMU is analyzing the behavior and performance of reg A and reg D regulation resources during this period.

Interchange on September 21, 2017

There were significant changes in the net RTO scheduled and actual interchange leading up to, and during the scarcity pricing event on September 21, 2017. The primary reason for these large changes the curtailment of transactions scheduled into and out of PJM resulting from TLRs, and the response to market signals. As Figure 3-58 shows, between 1100 and 1130, PJM had a change in net interchange of approximately 1,000 MW. This change was the result of the curtailment of 1,014 MW of net import transactions as a result of the TLR level 3B called by TVA for relief on the Volunteer-Philipps Bend 500 for the loss of Conasauga-Mosteller 500 constraint (Flowgate 1024). The same TLR resulted in additional curtailments effective at the top of each hour from 1300 through 1900. Other factors that affected interchange during the shortage pricing intervals included a TLR level 3A called by Ontario for relief on the Ontario-ITC constraint (Flowgate 9159), which resulted in additional net import curtailments starting at 1400, as well as market response to price signals between RTOs.

At 1400, the NYISO NYIS/PJM interface price was $490.98 and the PJM PJM/NYIS interface price was $143.38. This difference in interface prices resulted in additional exports from PJM to NYISO, approximately 800 additional MW of exports in hours 1400 and 1500. At 1400, the MISO MISO/PJM interface price was $310.39, and the PJM PJM/MISO interface price was $180.52. This difference in interface prices resulted in additional exports from PJM to MISO, approximately 800 additional MW of exports in hours 1400 and 1500.

Figure 3-58 Net RTO scheduled and actual interchange on September 21, 2017



CT Scheduling and Real Time Performance on September 21, 2017

PJM attempted to procure 5,236 MW of economically available generation from combustion turbine units between 1400 and 1700. Among the total economically available generation that PJM scheduled, 54 percent performed as offered, 27 percent ramped slower than the offered ramp rate and 18 percent did not reach their full output offered as economically available.

Operator load forecast bias on September 21, 2017

PJM dispatchers are allowed to increase or decrease (bias) the load forecast from SCED for the next ten minutes in the real time SCED software in order to correct for short term load forecast error.[100] Between 1400 and 1700, PJM's dispatchers lowered the forecast on average by 475 MW. For a few intervals, the load forecast was lowered by 1,300 MW. This reduced load forecast, in combination with curtailments in imports, could have resulted in SCED not dispatching enough units to meet load, and could have resulted in an overestimate of reserves during the peak hours on September 21, 2017. MMU analysis continues.

Accuracy of Reserve Measurement

Under the new shortage pricing mechanism, the determination of shortage of synchronized and primary reserves by the real-time SCED software is based on the measured and estimated levels of load, generation, interchange, demand response, and reserves. It also includes discretionary operator inputs to the ASO (Ancillary Service Optimizer) or SCED software. For the new shortage pricing mechanism to accurately reflect reserve shortage conditions, there needs to be accurate measurement of real-time reserves. That does not appear to be the case at present in PJM, but there does not appear to be any reason that PJM cannot implement that capability. Without very accurate measurement of reserves at minute by minute granularity, system operators cannot know with certainty that there is a shortage condition and therefore an appropriate trigger for five minute shortage pricing does not exist. The advantages of five minute shortage pricing are all implicitly based on the

100 Prior to July 17, 2017, the load forecast in the SCED software was for 15 minutes.

premise that the RTO knows accurately whether it is in a shortage condition. If PJM cannot demonstrate that it can accurately measure reserves at minute by minute granularity, it should not implement or continue five minute shortage pricing until it can demonstrate that capability.[101]

The Commission directed in the Final Rule that, to the extent an RTO/ISO needs to enhance its measurement capabilities to implement the shortage pricing requirement, it should propose to do so in its compliance filing.[102] PJM did not propose any enhancements to reserve measurement in the January 11th compliance filing.

In the period between May 11, 2017 and September 30, 2017, there were instances when the real time reserve data displayed on the PJM website showed synchronized reserves being short of the reserve requirement MW without shortage pricing being triggered. The real-time reserve data that is shown on the PJM website may not equal the RT SCED reserve estimate. This is because RT SCED estimates of reserve quantities were based on generation dispatch with a 15 minute look ahead interval, until July 16, 2017. On July 17, PJM reduced the RT SCED look-ahead interval from 15 minutes to 10 minutes, but the reserve quantities continue to be look-ahead estimates based on generation dispatch. The actual generation performance during that interval may not align with RT SCED and may result in a different calculated reserve quantity. However, PJM's implementation of five minute shortage pricing uses RT SCED estimate of reserves and not the real-time reserves as calculated and displayed on the PJM website. As a result, PJM's scarcity pricing does not reflect actual current scarcity conditions, but reflects the expected response of generation and load 10 minutes in the future.[103]

The accuracy of reserve measurement in PJM can be evaluated using historical data on performance during spinning events. The level of tier 1 biasing also reflects PJM dispatchers' estimate of the error in the measurement of tier 1 synchronized reserve. Both of these data sources provide insight into the accuracy of reserve measurement based on actual historical data.

101 See Comments of the Independent Market Monitor for PJM, Docket No. RM15-24-000 (December 1, 2015) at 9.
102 155 FERC ¶ 61,276 at P 177 (June 16, 2016).
103 Prior to July 17, 2017, PJM's scarcity pricing reflected the expected response of generation and load fifteen minutes in the future.

Historical Performance During Spinning Events

Historical data on response from synchronized reserves during spinning events shows the accuracy of PJM reserve estimates. Synchronized reserves consist of tier 1 and tier 2 synchronized reserves that are procured to meet the RTO and Mid-Atlantic reserve requirements. Tier 1 synchronized reserve is comprised of all online resources following economic dispatch and able to ramp up from their current output in response to a synchronized reserve event.[104]

All resources that respond to spinning events are paid for their response. Table 3-96 shows the performance of tier 1 and tier 2 synchronized reserves during spinning events, declared in 2015, 2016, and the first nine months of 2017 that lasted at least 10 minutes. In 2015, tier 1 response MW shown in Table 3-96 were measured as the increase in MW from all resources as a response to the spinning event declaration, regardless of whether the units were part of the tier 1 MW estimate. Since the tier 1 response MW to spinning events included resources that were not part of the tier 1 MW estimate, the 2015 estimates for tier 1 response were greater than 100 percent.

Beginning in 2016, PJM started reporting the response to spinning events only from the units that were part of its tier 1 estimate MW. Table 3-96 shows that, in 2016, the tier 1 MW response percent was never greater than 85 percent, with an average tier 1 response of 75 percent. In the first nine months of 2017, the tier 1 response was never greater than 75 percent, with an average tier 1 response of 60 percent.

If PJM is going to trigger shortage pricing based on shortage of synchronized reserves that is calculated based on current estimates, system operators will be relying on estimates of synchronized reserve MW that have historically been inaccurate.

104 See *2017 Quarterly State of the Market Report for PJM: January through September*, Section 10: Ancillary Service Markets at "Tier 1 Synchronized Reserve" for details on Tier 1 synchronized reserves.

Table 3-96 Performance of synchronized reserves during spinning events: January 1, 2015 through September 30, 2017[105]

Spin Event (Date, Hour)	Duration (Minutes)	Tier 1 Estimate MW (Adjusted by DGP)	Tier 1 Response MW	Tier 2 Scheduled MW	Tier 2 Response MW	Tier 1 Response Percent	Tier 2 Response Percent
Mar 3, 2015 12	11	1,079.0	1,365.1	484.4	272.3	126.5%	56.2%
Mar 16, 2015 06	24	541.5	576.4	248.0	180.2	106.4%	72.7%
Mar 17, 2015 19	17	1,428.9	1,693.1	247.2	232.8	118.5%	94.2%
Mar 23, 2015 19	15	851.3	1,420.0	273.5	205.8	166.8%	75.2%
Jul 30, 2015 10	10	1,458.4	2,145.7	79.7	24.0	147.1%	30.1%
Jan 18, 2016 17	12	861.0	733.5	616.7	508.8	85.2%	82.5%
Feb 8, 2016 15	10	1,750.2	1,338.2	228.4	200.1	76.5%	87.6%
Apr 14, 2016 20	10	1,182.8	1,000.6	346.3	304.8	84.6%	88.0%
Jul 28, 2016 13	15	649.4	500.4	822.9	655.8	77.1%	79.7%
Nov 4, 2016 17	11	744.5	497.1	758.0	709.2	66.8%	93.6%
Dec 31, 2016 05	12	971.2	585.0	594.4	485.7	60.2%	81.7%
Mar 23, 2017 06	24	926.8	566.7	742.8	559.1	61.1%	75.3%
Apr 08, 2017 11	10	1,222.6	827.2	879.3	828.7	67.7%	94.2%
May 08, 2017 04	10	1,325.6	976.3	335.1	298.5	73.6%	89.1%
Jun 08, 2017 03	10	974.4	726.7	575.7	522.4	74.6%	90.7%
Sep 04, 2017 20	15	476.3	68.1	601.0	563.8	14.3%	93.8%
Sep 21, 2017 14	16	305.8	217.4	1,253.9	1,037.3	71.1%	82.7%

Tier 1 Synchronized Reserve Estimate Bias

The tier 1 synchronized reserve for a unit is measured as the lower of the available 10 minute ramp and the difference between the economic dispatch point and the economic maximum output. The total supply of tier 1 synchronized reserve MW available to the market solution is calculated as the sum of the individual units' tier 1 MW, with further adjustments. These adjustments include eliminating tier 1 MW from nuclear, wind, solar, energy storage, and hydro units, adjusting the available tier 1 MW from remaining units using a metric called Degree of Generator Performance (DGP) and using tier 1 estimate bias.[106] Tier 1 biasing occurs when PJM market operations manually modifies (increasing or decreasing) the tier 1 synchronized reserve estimate of the market solution. This forces the market clearing engine to clear more or less tier 2 synchronized reserve and nonsynchronized reserve to satisfy the synchronized reserve and primary reserve requirements. Tier 1 biasing reflects the operators' view on the available tier 1 MW in the system and a lack of confidence on the calculated estimates of tier 1 MW, thus forcing the market clearing engine to procure more or less synchronized reserves. Table 10-14 shows the average monthly biasing of tier 1 estimates in the Ancillary Service Optimizer (ASO), the tool used to procure reserves on an hourly basis, in 2015 and 2016.

The existence of tier MW biasing raises the possibility that under a five minute shortage pricing construct, shortage pricing penalty factors may be triggered or avoided not due to actual reserve levels, but by operators' discretionary decisions on the amount of available reserves. It is possible that the market engine's estimate of tier 1 MW, even after unit level adjustments such as DGP, may be enough to satisfy the reserve requirement, but an operator's biasing of the market engine's estimate may lead to triggering shortage pricing penalty factors. There are no rules in the PJM tariff or manuals regarding the use of tier 1 MW biasing. In a five minute shortage pricing construct, the need for explicit rules governing operator discretion regarding reserve estimates becomes critical. The MMU has recommended since 2012 that PJM explicitly define the rules for using tier 1 biasing and identify which rule permits it every time tier 1 synchronized reserve estimate biasing is used.

Generator Data used for Reserve Estimates

A potential source for the error in tier 1 MW is the use of economic dispatch point to calculate the available ramp limited MW in 10 minutes as opposed to the actual output from the generator for any 5 minute interval. The amount of tier 1 MW available from a resource may differ due to using the metered output from a unit versus the market clearing engine's estimate of the resource's output. PJM addressed this issue partially in 2015 by adjusting a resource's available 10 minute ramp with its DGP. The available tier 1 MW estimated by the market solution for each resource is adjusted by its DGP percent. PJM communicates to generation operators whose tier 1 MW is part of the market solution the latest estimate of units' tier 1 MW and units' current resource specific DGP.

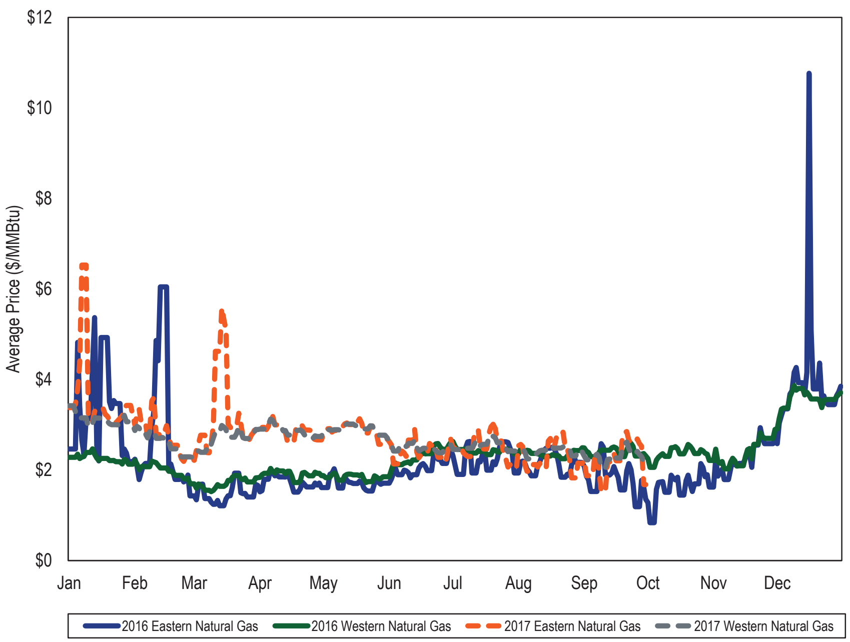
105 Beginning January 2015, Degree of Generator Performance (DGP) was introduced as a metric to improve the accuracy of the tier 1 MW estimate used by the market solution.
106 DGP measures how closely the unit has been following economic dispatch for the past 30 minutes.

PJM Cold Weather Operations 2017

Natural Gas Supply and Prices

As of September 30, 2017, gas fired generation was 36.4 percent (66,335.9 MW) of the total installed PJM capacity (182,459.2 MW).[107] Figure 3-59 shows the average daily price of delivered natural gas for eastern and western parts of PJM service territory in 2017 and 2016.[108]

Figure 3-59 Average daily delivered price for natural gas: January 1, 2016 through September 30, 2017 ($/MMBtu)



During the first nine months of 2015, 2016 and 2017, a number of interstate gas pipelines that supply fuel for generators in the PJM service territory issued restriction notices limiting the availability of nonfirm transportation services. These notices include warnings of operational flow orders (OFO) and actual OFOs. OFOs may, depending on the nature of the transportation service purchased, permit the pipelines to 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 gas day, with penalties for deviating from the nominated quantities. Pipelines may also enforce strict balancing constraints which limit the ability of gas users, depending on the nature of the transportation service purchased, to deviate from the 24 hour ratable take and which may 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.

107 *2017 Quarterly State of the Market Report for PJM: January through June*, Section 5: Capacity Market, at Installed Capacity.
108 Eastern natural gas consists of the average of Texas Eastern 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 City gate daily fuel price indices.