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 2018, including market size, concentration, pivotal suppliers, offer behavior, and price.[1] The MMU concludes that the PJM energy market results were competitive in the first nine months of 2018.

Table 3-1 The energy market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Partially Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

- The aggregate market structure was evaluated as partially competitive because the aggregate market power test based on pivotal suppliers indicates that the aggregate day-ahead and real-time market structure was not competitive on every day. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM energy market in the first nine months of 2018 was unconcentrated by FERC HHI standards in 92.4 percent of market hours and moderately concentrated in 7.6 percent of market hours. Average HHI was 847 with a minimum of 624 and a maximum of 1242 in the first nine months of 2018. The PJM energy market peaking segment of supply was highly concentrated. 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 and the real-time 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 local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints and local reliability issues. 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 represents economic withholding and the markups of those participants affected LMP.

- 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,

1 Analysis of 2018 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 *2017 State of the Market Report for PJM*, Appendix A, "PJM Geography."

their marginal costs in both Day-Ahead and Real-Time Energy Markets, although high markups during periods of high demand did affect prices.

- Market design was evaluated as effective because the analysis shows that the PJM energy market resulted in competitive market outcomes. In 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 are 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, imports and virtual transactions. The maximum average on peak hourly offered real-time supply was 114,869 MWh for the spring and 140,951 MWh for the summer. In the first nine months of 2018, 7,945.4 MW of new resources were added and 4,894.2 MW were retired.

  PJM average real-time cleared generation in the first nine months of 2018 increased by 4.3 percent from the first nine months of 2017, from 91,658 MWh to 95,561 MWh.

  PJM average day-ahead cleared supply in the first nine months of 2018, including INCs and up to congestion transactions, decreased by 13.0 percent from the first nine months of 2017, from 133,377 MWh to 116,068 MWh.

- **Aggregate Pivotal Suppliers.** The PJM energy market at times requires generation from pivotal suppliers to meet load, resulting in aggregate market power even when the HHI level indicates that the aggregate market is unconcentrated.

- **Generation Fuel Mix.** In the first nine months of 2018, coal units provided 29.2 percent, nuclear units 33.8 percent and natural gas units 30.7 percent of total generation. Compared to the first nine months of 2017, generation from coal units decreased 5.2 percent, generation from natural gas units increased 19.4 percent and generation from nuclear units decreased 0.2 percent.

- **Fuel Diversity.** In the first nine months of 2018, the fuel diversity of energy generation, measured by the fuel diversity index for energy (FDI_e), increased 0.7 percent over the FDI_e for the first nine months of 2017.

- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first nine months of 2018, coal units were 29.7 percent of marginal resources and natural gas units were 62.1 percent of marginal resources. In the first nine months of 2017, coal units were 32.5 percent and natural gas units were 52.9 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market, in the first nine months of 2018, up to congestion transactions were 63.9 percent of marginal resources, INCs were 9.2 percent of marginal resources, DECs were 16.1 percent of marginal resources, and generation resources were 10.7 percent of marginal resources. 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.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM accounting peak load during the first nine months of 2018 was 147,042 MWh in the HE 1700 on August 28, 2018, which was 4,656 MWh, 3.3 percent, higher than the PJM peak load for the first nine months of 2017, which was 142,387 MWh in the HE 1800 on July 19, 2017.

  PJM average real-time demand in the first nine months of 2018 increased by 5.5 percent from the first nine months of 2017, from 87,243 MWh to 92,047 MWh. PJM average day-ahead demand in the first nine months of 2018, including DECs and up to congestion transactions, decreased by 13.1 percent from the first nine months of 2017, from 128,450 MWh to 111,589 MWh.

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM do so using a combination of self-supply, bilateral market purchases and spot market purchases. For the first nine months of 2018, 12.8 percent of real-time load was supplied by bilateral contracts, 29.7 percent by spot market purchases and 58.6 percent by self-supply. Compared to the first nine months of 2017, reliance on bilateral contracts decreased by 1.6 percentage points, reliance on spot market purchases increased by 2.2 percentage points and reliance on self-supply decreased by 0.2 percentage points.

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 increased from 0.0 percent in the first nine months of 2017 to 0.1 percent in the first nine months of 2018. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.3 percent in the first nine months of 2017 to 1.0 percent in the first nine months of 2018. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation.

  In the first nine months of 2018, 14 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, including for reactive support. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours remained at 0.1 percent in the first nine months of 2017 and 2018. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours remained at 0.1 percent in the first nine months of 2017 and 2018.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the first nine months of 2018, in the PJM Real-Time Energy Market, 89.8 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 negative when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive when using unadjusted cost-based 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-based offers, the highest markup for any marginal unit in the first nine months of 2018 was more than $500 per MWh while the highest markup in the first nine months of 2017 was more than $700 per MWh. During the period of cold weather and high demand in January, several units in the PJM market were offered with high markups.

  In the first nine months of 2018, in the PJM Day-Ahead Energy Market, 95.2 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 negative when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive when using unadjusted cost-based offers. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the first nine months of 2018 was about $200 per MWh, while the highest markup in the first nine months of 2017 was about $50 per MWh.

- **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 2018, the average hourly increment offers submitted and cleared MW decreased by 32.3 percent and 47.0 percent, from 8,490 MW and 4,858 MW in the first nine months of 2017 to 5,746 MW and 2,577 MW in the first nine months of 2018. The average hourly decrement bids submitted and cleared MW decreased by 17.3 percent and 34.9 percent, from 8,318 MW and 4,380 MW in the first nine months of 2017 to 6,879 MW and 2,851 MW in the first nine months of 2018. The average hourly up to congestion submitted and cleared MW decreased by 58.8 percent and 48.4 percent, from 145,556 MW and 34,203 MW in the first nine months of 2017 to 60,036 MW and 17,639 MW in the first nine months of 2018.

- **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 by MW in the first nine months of 2018, 23.3

percent were offered as available for economic dispatch, 29.8 percent were offered at the economic minimum, 4.8 percent were offered as emergency dispatch, 17.5 percent were offered as self scheduled, and 23.5 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 2018 compared to the first nine months of 2017. The load-weighted, average real-time LMP was 29.9 percent higher in the first nine months of 2018 than in the first nine months of 2017, $39.43 per MWh versus $30.36 per MWh.

  PJM day-ahead energy market prices increased in the first nine months of 2018 compared to the first nine months of 2017. The load-weighted, average day-ahead LMP was 27.9 percent higher in the first nine months of 2018 than in the first nine months of 2017, $38.71 per MWh versus $30.26 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, in the first nine months of 2018, 19.8 percent of the load-weighted LMP was the result of coal costs, 39.2 percent was the result of gas costs and 0.76 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market, in the first nine months of 2018, 15.5 percent of the load-weighted LMP was the result of coal costs, 29.2 percent was the result of DEC bids, 18.6 percent was the result of gas costs, 18.1 percent was the result of INC offers, and 3.0 percent was the result of up to congestion transaction offers.

- **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 2018, the unadjusted markup component of LMP was $5.15 per MWh or 13.1 percent of the PJM load-weighted, average LMP. January had the highest unadjusted off peak markup component, $11.65 per MWh, or 13.28 percent of the real-time, off peak hour load-weighted, average LMP. There were 38 hours in the first nine months of 2018 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded $99.63 per MWh. During the period of cold weather and high demand in January, several units in the PJM market were offered with high markups.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In the first nine months of 2018, the unadjusted markup component of LMP resulting from generation resources was $0.67 per MWh or 1.7 percent of the PJM day-ahead load-weighted average LMP. January had the highest unadjusted peak markup component, $4.04 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 represents 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 2017 and $0.48 per MWh in the first nine months of 2018. The difference between average day-ahead and real-time prices, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

- There were no five minute shortage pricing events in the first nine months of 2018. On May 29, 2018, there were six Performance Assessment Intervals (PAIs) triggered in the Edison area of the AEP Zone due to a localized load shed event. On July 18, 2018, there were 18 PAIs triggered in the Lonesome Pine area on the border of Virginia and West Virginia in the AEP Zone due to a localized load shed event to control for voltage violations.

Recommendations

Market Power

- The MMU recommends that the market rules should explicitly require that offers in 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. The MMU recommends that the level of incremental costs includable in cost-based offers not exceed the short run marginal cost of the unit. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the tariff be changed to allow units to have Fuel Cost Policies that do not include fuel procurement practices, including fuel contracts. Fuel procurement practices, including fuel contracts, may be used as the basis for Fuel Cost Policies but should not be required. (Priority: Low. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends that PJM change the Fuel Cost Policy requirement to apply only to units that will be offered with non-zero cost-based offers. The PJM market rules should require that the cost-based offers of units without an approved Fuel Cost Policy be set to zero. (Priority: Low. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends that Manual 15 (Cost Development Guidelines) be replaced with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based 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: Low. 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: Partially 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. The TPS test application in the Day-Ahead Energy Market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. 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-based offers. (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 price-based non-PLS 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 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, 2017.)
- 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 Market Sellers not be allowed to designate any portion of an available Capacity Resource's ICAP equivalent of cleared UCAP capacity commitment as a Maximum Emergency offer at any time during the delivery year.[4] (Priority: Medium. First reported 2012. Status: Not adopted.)

Capacity Performance Resources

- 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 the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity performance construct. The operational parameters used by generation owners to indicate to PJM dispatchers what a unit is capable of during the operating day should not determine capacity performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- 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. (Priority: Low. First reported 2014. Status: Not Adopted.)
- The MMU recommends that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs) in the capacity market default offer cap, and only include those events that trigger emergencies for at least a defined sub-zonal or zonal level. (Priority: Medium. New Recommendation. Status: Not adopted.)
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's

4 This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See Schedule 1, Section 1.10.1A(d), Revisions to the PJM Open Access Transmission Tariff and PJM Operating Agreement (Marked/Redline Format), EL15-29-000 (December 12, 2014). FERC rejected the proposed change. See 151 FERC ¶ 61,208 at P 476 (2015).

implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. New Recommendation. Status: Not adopted.)

Accurate System Modeling

- 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 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 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: Adopted, 2012.)
- The MMU recommends that PJM include in the tariff or 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] [6] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load 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 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 increase the interaction of outage and operational restrictions data submitted by Market Participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)

Transparency

- The MMU recommends that PJM market rules require the fuel type be identified for every price and cost schedule and PJM market rules 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 continue to enhance its posting of market data to promote market efficiency. (Priority: Medium. First reported 2005. Status: Partially adopted.)

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.

6 There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first nine months of 2018, 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 increased by 3,902 MWh, 4.3 percent, and peak load increased by 4,656 MWh, 3.3 percent, in the first nine months of 2018 compared to the first nine months of 2017. 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. The market structure of the PJM aggregate energy market is partially competitive because aggregate market power does exist for a significant number of hours. The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. It is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. The current market power mitigation rules for the PJM energy market rely on the assumption that the ownership structure of the aggregate market ensures competitive outcomes. 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. There are pivotal suppliers in the aggregate energy market at times. High markups for some units demonstrate the potential to exercise market power during high demand conditions. The existing market power mitigation measures do not address aggregate market power. The MMU is developing an aggregate market power test and will propose market power mitigation rules to address aggregate market power.

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] 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. These issues can be resolved by simple rule changes.

The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. A competitive offer is equal to short run marginal costs. 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 rule changes to incorporate a clear and accurate definition of short run marginal costs.

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 to serve load in each market interval. 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 2018 generally reflected supply-demand fundamentals, although the behavior of some participants during high demand periods represents 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 economically withhold or physically withhold.

Prices in PJM are not too low. There is no evidence to support the need for a significant change to the calculation of LMP. The underlying problem that fast start pricing and PJM's convex hull pricing approach are attempting to

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

address is actually scarcity pricing, including the impact of operator actions on the definition of scarcity. Prices do not reflect market conditions when the market is tight. Rather than undercutting the basic LMP logic that is core to market efficiency, it would make more sense to directly address scarcity pricing, operator actions and the design of reserve markets. Targeted increases to the demand for reserves when the market is tight would address price formation in the energy market.

The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs would create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff would exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff would be created by PJM's fast start pricing proposal and in a much more extensive form by PJM's modified convex hull pricing proposal.

The fast start pricing and convex hull solutions would undercut LMP logic rather than directly addressing the underlying issues. The solution is not to accept that the inflexible CT should be paid or set price based on its commitment costs rather than its short run marginal costs. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why this unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying excess uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

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, that scarcity pricing only occurs when scarcity exists, 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. However, the explicit balancing mechanism that included net revenues directly in unit offers in the prior capacity market design is not present in the Capacity Performance design. The nature of a direct and explicit energy pricing net revenue true up mechanism in the capacity market should be addressed if energy revenues are expected to increase as a result of scarcity events, as a result of increased demand for reserves, or as a result of PJM's inappropriate proposals related to fast start pricing and the inclusion of maintenance expenses as short run marginal costs. The true up mechanism must address both cleared auctions and subsequent auctions. 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 the first nine months of 2018 or prior years. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during high demand periods represents economic withholding. Markups were higher in the first nine months of 2018, primarily as a result of markups during the cold weather in January. Given the structure of the energy market which can permit the exercise of aggregate market power at times of high demand, the change in some participants' behavior is a source of concern in the energy market and provides a reason to use correctly defined short run marginal 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 2018.

Market Structure

Market Concentration

Analysis of supply curve segments of the PJM energy market in the first nine months of 2018 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 a highly concentrated market structure. It is possible to have an exercise of market power even when the HHI level does not indicate a highly concentrated market structure.

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 2018, 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 cheaper of the cost and price schedules, and the lack of rules requiring that cost-based offers equal 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).

In theory, the HHI provides insight into the relationship between market structure, behavior, and performance. In the case where participants compete by producing output at constant, but potentially different, marginal costs, the HHI is directly proportional to the expected average price cost markup in the market:[9]

$$\frac{HHI}{\varepsilon} = \frac{P - MC}{P}$$

where ε is the absolute value of the price elasticity of demand, *P* is the market price, and *MC* is the average marginal cost of production. The left side of the equation quantifies market structure, and the right side of the equation measures market performance. The assumed participant behavior is profit maximization. If HHI is very low, implying a more competitive market, prices converge to marginal cost, the competitive market outcome. But even a low HHI may result in substantial markup with a low price elasticity of demand. If HHI is very high, meaning competition is lacking, prices approach the monopoly level. Price elasticity of demand (ε) determines the degree to which suppliers with market power can impose higher prices on consumers.

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

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.

9 *See* Tirole, Jean. *The Theory of Industrial Organization*, MIT (1988), Chapter 5: Short-Run Price Competition.

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.[10]

The PJM energy market HHIs and the FERC concentration cutoffs may understate the degree of market power because, in the absence of aggregate market power mitigation, even the unconcentrated HHI level would imply substantial markups due to the low short run price elasticity of demand. For example, research estimates find short run demand elasticity ranging from -0.2 to -0.4.[11] These elasticities imply, for example, an average markup ranging from 25 to 50 percent at the unconcentrated to moderately concentrated threshold HHI of 1000:[12]

$$\frac{HHI}{\varepsilon} = \frac{0.1}{0.2} = \frac{P - MC}{P} = 50\%$$

With marginal costs of $33 per MWh and an average HHI of 847, average PJM prices theoretically range from $42 to $57 per MWh, exceeding marginal costs as a result of the exercise of market power. Actual prices and markups are lower than the theoretical range, supporting the MMU's competitive assessment of the market. However, markup is not zero. In some hours, markup and prices reach levels that reflect the exercise of market power.

PJM HHI Results

Calculations for hourly HHI indicate that by FERC standards, the PJM energy market during the first nine months of 2018 was unconcentrated (Table 3-2).

Table 3-2 Hourly energy market HHI: January through September, 2017 and 2018[13]

	Hourly Market HHI (Jan - Sep, 2017)	Hourly Market HHI (Jan - Sep, 2018)
Average	929	847
Minimum	696	624
Maximum	1208	1242
Highest market share (One hour)	27%	27%
Average of the highest hourly market share	18%	19%
# Hours	6,551	6,551
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-3 includes HHI values by supply curve segment, including base, intermediate and peaking plants for the first nine months of 2017 and 2018. The PJM energy market was unconcentrated overall with low concentration in the baseload, moderate concentration in the intermediate segment, and high concentration in the peaking segment.

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

11 See Patrick, Robert H. and Frank A. Wolak (1997), "Estimating the Customer-Level Demand for Electricity Under Real-Time Market Prices, <https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/Estimating%20the%20Customer-Level%20Demand%20for%20Electricity%20Under%20Real-Time%20Market%20Prices_Aug%201997_Patrick,%20Wolak.pdf>, last accessed August 3, 2018 and Fan, Shu and Rob Hyndman (2010), "The price elasticity of electricity demand in South Australia," <https://robjhyndman.com/papers/Elasticity2010.pdf>.

12 The HHI used in the equation is based on market shares. For the FERC HHI thresholds and standard HHI reporting, market shares are multiplied by 100 prior to squaring the market shares.

13 This analysis includes all hours in the first nine months of 2017 and 2018, regardless of congestion.

Table 3-3 Hourly energy market HHI (By supply segment): January through September, 2017 and 2018

	Jan - Sep, 2017			Jan - Sep, 2018		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	831	982	1254	725	892	1283
Intermediate	779	1740	9894	733	1483	5030
Peak	705	5967	10000	679	6071	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 2018.

Figure 3-1 Fuel source distribution in unit segments: January through September, 2018[14]

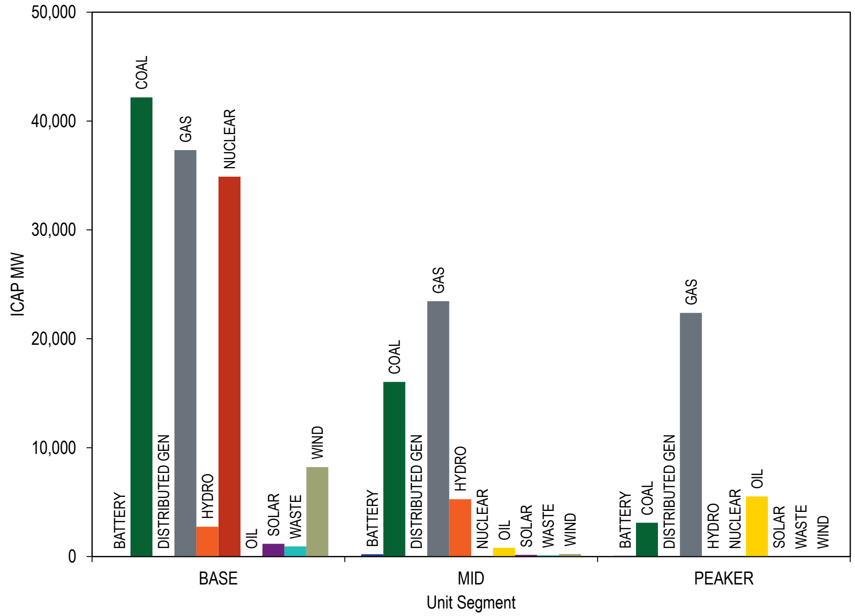
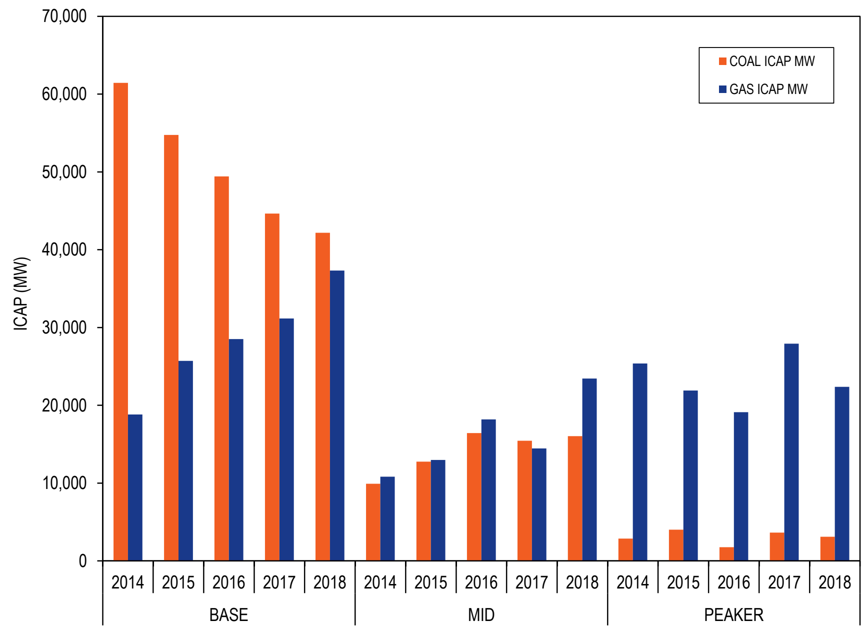


Figure 3-2 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking segments for the first nine months of 2014 through 2018. Figure 3-2 shows that the total ICAP of coal fired units in PJM that are classified as baseload has been steadily decreasing and the total ICAP of gas fired units in PJM that are classified as baseload is steadily increasing using operating history for the first nine months during the period from 2014 through 2018, although coal fired baseload MW still exceed gas fired baseload MW.

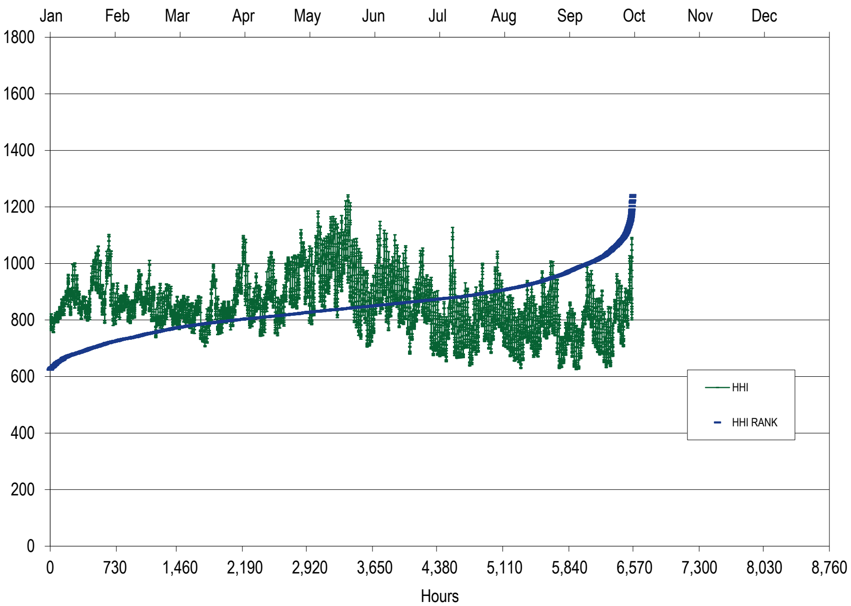
Figure 3-2 Unit segment classification by fuel: January through September, 2014 through 2018



14 The units classified as Distributed Gen are buses within Electric Distribution Companies (EDCs) that are modeled as generation buses to accurately reflect net energy injections from distribution level load buses. The modeling change was the outcome of the Net Energy Metering Task Force stakeholder group in July, 2012. See PJM. "Net Energy Metering Senior Task Force (NEMSTF) 1st Read - Final Report and Proposed Manual Revisions" (June 28, 2012) <http://www.pjm.com/~/media/committees-groups/task-forces/nemstf/postings/20120628-first-read-item-04-nemstf-report-and-proposed-manual-revisions.ashx>.

Figure 3-3 presents the hourly HHI values in chronological order and an HHI duration curve for the first nine months of 2018.

Figure 3-3 Hourly energy market HHI: January through September, 2018



Merger Reviews

FERC reviews contemplated dispositions, consolidations, acquisitions, and changes in control of jurisdictional generating units and transmission facilities under section 203 of the Federal Power Act to determine whether such transactions are "consistent with the public interest."[15]

FERC applies tests set forth in the 1996 Merger Policy Statement.[16] FERC currently is reviewing those guidelines.[17]

The 1996 Merger Policy Statement provides for review of jurisdictional transactions based on "(1) the effect on competition; (2) the effect on rates; and (3) the effect on regulation." FERC adopted the 1992 Department of Justice Guidelines and the Federal Trade Commission Horizontal Merger Guideline (1992 Guidelines) to evaluate the effect on competition. Following the 1992 Guidelines, the FERC applies a five step framework, which includes: (1) defining the market; (2) analyze market concentration; (3) analyze mitigative effects of new entry; (4) assess efficiency gains; and (5) assess viability of parties without merger. The FERC also applies a Competitive Analysis Screen.

The MMU reviews proposed mergers based on a three pivotal supplier test applied to the actual operation of the PJM market. The MMU routinely files comments including such analyses.[18] The MMU has proposed that FERC adopt this approach when evaluating mergers in PJM.[19] FERC has considered the MMU's analysis in reviewing mergers.[20]

The MMU has also facilitated settlements for mitigation of market power, in cases where market power concerns have been identified.[21] Such mitigation generally is designed to mitigate behavior over the long term, in addition to or instead of imposing short term asset divestiture requirements.

Legislation limiting the scope of section 203 reviews has passed Congress (H.R. 1109). The legislation limits the transactions reviewed to those facilities valued more than $10,000,000. In order to avoid breaking up transactions to evade review, the legislation also requires FERC to establish a notice requirement rule for transactions involving facilities valued at more than $1,000,000. The legislation requires that such rule "minimize the paperwork burden resulting from the collection of information."

15 18 U.S.C. § 824b.

16 See Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996) (1996 Merger Policy Statement), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997). See also FPA Section 203 Supplemental Policy Statement, FERC Stats. & Regs. ¶ 31,253 (2007), *order on clarification and reconsideration*, 122 FERC ¶ 61,157 (2008).

17 See 156 FERC ¶ 61,214 (2016); FERC Docket No. RM16-21-000.

18 See, e.g., Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-141-000 (Nov. 10, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-96-000 (July 21, 2014) Comments of the Independent Market Monitor for PJM, FERC Docket No. EC11-83-000 (July 21, 2011); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-14 (Dec. 9, 2013) Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-112-000 (Sept. 15, 2014)

19 See Comments of the Independent Market Monitor for PJM, Docket No. RM16-21 (Dec. 12, 2016).

20 See *Dynegy Inc., et al.*, 150 FERC ¶ 61, 231 (2015); *Exelon Corporation, Constellation Energy Group, Inc.*, 138 FERC ¶ 61,167 (2012); NRG *Energy Holdings, Inc., Edison Mission Energy*, 146 FERC ¶ 61,196 (2014); *see also Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶ 61,109 (2012).

21 See 138 FERC ¶ 61,167 at P 19.

Aggregate Market Pivotal Supplier Results

Notwithstanding the HHI level, a supplier may have the 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.

In the PJM Day-Ahead Energy Market, two suppliers were jointly pivotal on 13.6 percent of days, and three suppliers were jointly pivotal on 59.0 percent of days in the first nine months of 2018. In the PJM Real-Time Energy Market, three suppliers were jointly pivotal in 8.0 percent of hours with increasing demand during the first nine months of 2018. The frequency of pivotal suppliers increased during the summer months of 2017 and 2018, on high demand days in September 2017 and 2018, and from January 1 to 10, 2018.

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.[22] 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.

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.[23] 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 3-4 shows the number of days in 2017 and in the first nine months of 2018 with one pivotal supplier, two jointly pivotal suppliers, and three jointly pivotal suppliers for the Day-Ahead Energy Market. No supplier was singly pivotal for any day in 2017 or in the first nine months of 2018. Two suppliers were jointly pivotal on 38 days in the first nine months of 2018. Three suppliers were jointly pivotal on 161 days, despite average HHIs at persistently unconcentrated levels. In both 2017 and 2018, the third quarter exhibits the highest levels of aggregate market power, concurrent with PJM's peak load season.

22 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).

23 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 3-4 Days with pivotal suppliers and numbers of pivotal suppliers in the Day-Ahead Energy Market by quarter

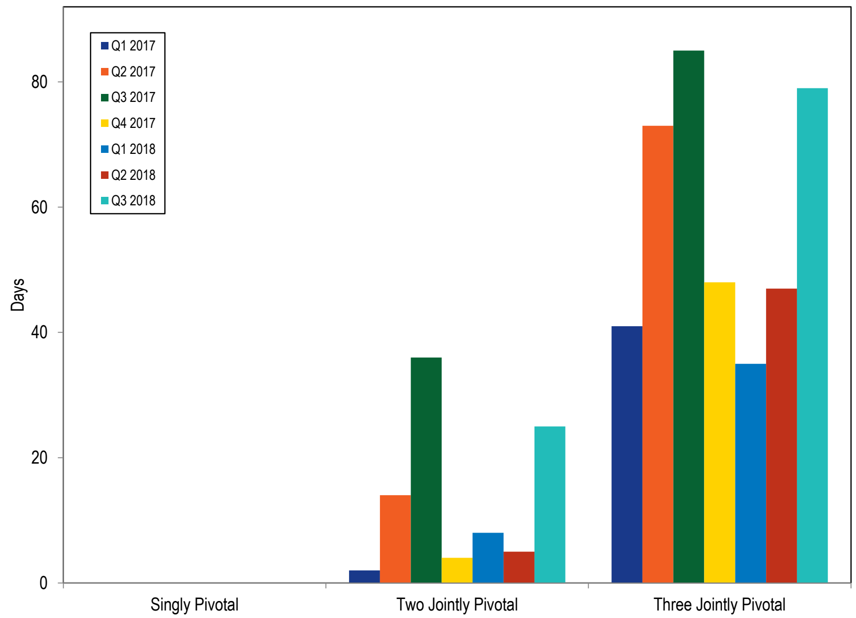


Table 3-4 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the Day-Ahead Energy Market in the first nine months of 2018. The two largest suppliers were one of two pivotal suppliers on 37 days, 13.6 percent of days in the first nine months of 2018. All of the top 10 suppliers were one of three pivotal suppliers on at least 13.6 percent of days, and the largest two suppliers were one of three pivotal suppliers on at least 59.0 percent of days.

Table 3-4 Day-ahead market pivotal supplier frequency: January through September, 2018

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	0.0%	37	13.6%	161	59.0%
2	0	0.0%	36	13.2%	160	58.6%
3	0	0.0%	27	9.9%	119	43.6%
4	0	0.0%	20	7.3%	121	44.3%
5	0	0.0%	17	6.2%	134	49.1%
6	0	0.0%	14	5.1%	131	48.0%
7	0	0.0%	5	1.8%	69	25.3%
8	0	0.0%	4	1.5%	62	22.7%
9	0	0.0%	4	1.5%	37	13.6%
10	0	0.0%	3	1.1%	77	28.2%

Real-Time Energy Market Aggregate Pivotal Suppliers

To assess the number of pivotal suppliers in the Real-Time Energy Market, the MMU determined, for each supplier at the start of each hour, the MW available for economic dispatch and/or commitment that were already running or were available to start within the next operating hour. The available supply is defined as MW achievable within one hour, and 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.[24] Generating units are included for each supplier. Demand is the increase in total MW required to meet physical load and export transactions. Hours with decreased demand are not included. A supplier is pivotal if PJM would require some portion of the supplier's available economic capacity to meet the increase in system demand over the next operating hour. Suppliers are jointly pivotal if PJM would require some portion of the joint suppliers' available economic capacity to meet the increase in system demand over the next operating hour.

Figure 3-4 shows the number of hours in the first nine months of 2018 with one pivotal supplier, two jointly pivotal suppliers, and three jointly pivotal suppliers for the Real-Time Energy Market. At least one supplier was singly pivotal in 21 hours in the first nine months of 2018. Two suppliers were

24 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.

jointly pivotal in 76 hours in the first nine months of 2018. Three suppliers were jointly pivotal in 253 hours.

Figure 3-5 Hours with pivotal suppliers and numbers of pivotal suppliers in the Real-Time Energy Market by quarter

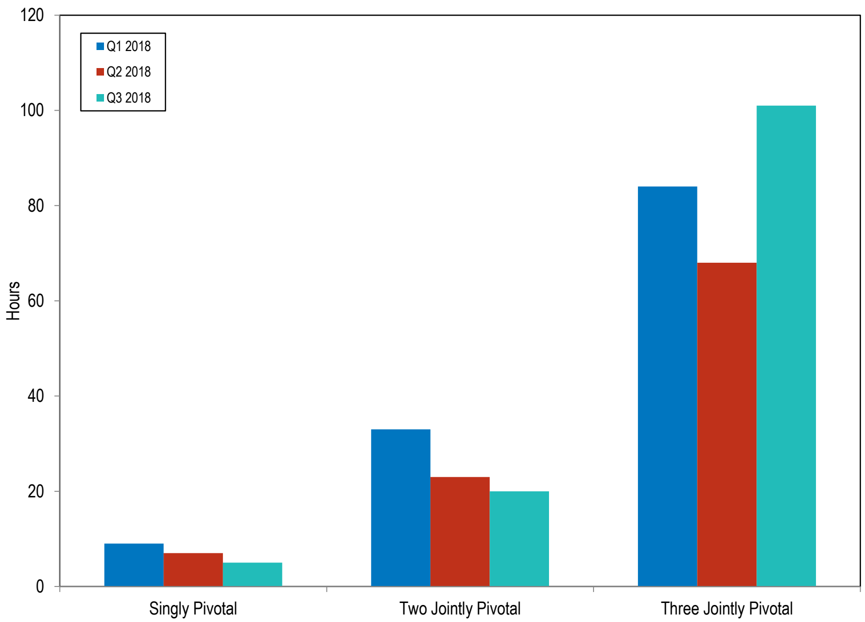


Table 3-4 provides the frequency with which each of the top 10 pivotal suppliers was pivotal in the Real-Time Energy Market in the first nine months of 2018. The largest supplier was singly pivotal in 15 hours, 0.5 percent of hours with increasing demand in the first nine months of 2018.

Table 3-5 Real-time market pivotal supplier frequency: January through September, 2018

Pivotal Supplier Rank	Hours Singly Pivotal	Percent of Hours	Hours Jointly Pivotal with One Other Supplier	Percent of Hours	Hours Jointly Pivotal with Two Other Suppliers	Percent of Hours
1	15	0.5%	65	2.0%	236	7.4%
2	8	0.3%	42	1.3%	164	5.2%
3	6	0.2%	61	1.9%	236	7.4%
4	6	0.2%	41	1.3%	157	4.9%
5	5	0.2%	22	0.7%	77	2.4%
6	4	0.1%	21	0.7%	72	2.3%
7	4	0.1%	20	0.6%	73	2.3%
8	4	0.1%	19	0.6%	77	2.4%
9	4	0.1%	15	0.5%	60	1.9%
10	4	0.1%	12	0.4%	48	1.5%

Ownership of Marginal Resources

Table 3-6 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.[25] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of the first nine months of 2018, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. In the first nine months of 2018, the offers of one company resulted in 13.3 percent of the real-time, load-weighted PJM system LMP and the offers of the top four companies resulted in 41.9 percent of the real-time, load-weighted, average PJM system LMP. During the first nine months of 2017, the offers of one company resulted in 13.6 percent of the real-time, load-weighted PJM system LMP and offers of the top four companies resulted in 50.0 percent of the real-time, load-weighted, average PJM system LMP. In the first nine months of 2018, the offers of one company resulted in 12.1 percent of the peak hour real-time, load weighted 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. The decline in the concentration of marginal resource ownership largely paralleled the decline in the share of marginal coal resources in the real time energy market. In the PJM energy market, the ownership of coal resources is highly concentrated unlike the ownership of new entrant natural gas resources.

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

Table 3-6 Marginal unit contribution to real-time, load-weighted LMP (By parent company): January through September, 2017 and 2018

2017 (Jan - Sep)						2018 (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	13.6%	13.6%	1	13.2%	13.2%	1	13.3%	13.3%	1	12.1%	12.1%
2	13.5%	27.1%	2	12.0%	25.2%	2	10.0%	23.3%	2	10.4%	22.5%
3	12.6%	39.7%	3	10.6%	35.8%	3	10.0%	33.3%	3	10.0%	32.5%
4	10.3%	50.0%	4	10.1%	45.9%	4	8.6%	41.9%	4	8.0%	40.5%
5	9.7%	59.6%	5	9.7%	55.6%	5	6.6%	48.5%	5	6.0%	46.5%
6	4.4%	64.0%	6	5.8%	61.5%	6	4.7%	53.3%	6	5.5%	52.0%
7	3.8%	67.7%	7	5.0%	66.4%	7	4.7%	57.9%	7	5.4%	57.4%
8	3.6%	71.4%	8	3.5%	69.9%	8	4.5%	62.5%	8	4.9%	62.3%
9	3.5%	74.8%	9	3.3%	73.2%	9	3.8%	66.3%	9	3.2%	65.5%
Other (74 companies)	25.2%	100.0%	Other (68 companies)	26.8%	100.0%	Other (79 companies)	33.7%	100.0%	Other (76 companies)	34.5%	100.0%

Table 3-7 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[26] 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 2018, the offers of one company contributed 12.1 percent of the day-ahead, load-weighted, PJM system LMP and that the offers of the top four companies contributed 30.8 percent of the day-ahead, load-weighted, average, PJM system LMP. 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 offers of the top four companies contributed 30.4 percent of the day-ahead, load-weighted, average PJM system LMP.

Table 3-7 Marginal resource contribution to day-ahead, load-weighted LMP (By parent company): January through September, 2017 and 2018

2017 (Jan - Sep)						2018 (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	9.6%	9.6%	1	12.0%	12.0%	1	12.1%	12.1%	1	14.1%	14.1%
2	8.1%	17.7%	2	6.9%	6.9%	2	7.2%	19.3%	2	7.1%	21.2%
3	6.7%	24.4%	3	5.3%	5.3%	3	6.1%	25.4%	3	5.4%	26.6%
4	6.0%	30.4%	4	5.1%	5.1%	4	5.4%	30.8%	4	5.0%	31.6%
5	5.5%	35.9%	5	4.9%	4.9%	5	4.8%	35.5%	5	5.0%	36.6%
6	5.3%	41.2%	6	4.7%	4.7%	6	4.4%	40.0%	6	4.9%	41.5%
7	4.9%	46.1%	7	4.6%	4.6%	7	4.2%	44.2%	7	4.1%	45.6%
8	4.4%	50.5%	8	4.5%	4.5%	8	3.8%	48.0%	8	3.9%	49.5%
9	3.8%	54.4%	9	4.3%	4.3%	9	3.7%	51.7%	9	3.5%	53.0%
Other (153 companies)	45.6%	100.0%	Other (148 companies)	47.6%	47.6%	Other (162 companies)	48.3%	100.0%	Other (148 companies)	47.0%	100.0%

26 Id.

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 3-8 shows the type of fuel used by marginal resources in the Real-Time Energy Market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first nine months of 2018, coal units were 29.7 percent and natural gas units were 62.1 percent of marginal resources. In the first nine months of 2017, coal units were 32.5 percent and natural gas units were 52.9 percent of the total marginal resources. In the first nine months of 2018, 72.5 percent of the wind marginal units had negative offer prices, 25.0 percent had zero offer prices and 2.5 percent had positive offer prices. In the first nine months of 2017, 74.1 percent of the wind marginal units had negative offer prices, 19.0 percent had zero offer prices and 6.9 percent had positive offer prices.

The proportion of marginal nuclear units increased from 0.03 percent in the first nine months of 2015 to 1.06 percent in the first nine months of 2018. Most nuclear units are offered as fixed generation in the PJM market. A small number of nuclear units were offered with a dispatchable range since 2016. The dispatchable nuclear units do not always respond to dispatch instructions.

Table 3-8 Type of fuel used (By real-time marginal units): January through September, 2014 through 2018

	(Jan - Sep)				
Type/Fuel	2014	2015	2016	2017	2018
Gas	42.48%	34.88%	41.41%	52.92%	62.10%
Coal	49.71%	54.46%	46.21%	32.53%	29.71%
Oil	3.44%	7.39%	8.55%	4.45%	3.96%
Wind	3.86%	2.74%	2.67%	8.44%	2.78%
Uranium	0.06%	0.03%	0.92%	1.25%	1.06%
Other	0.35%	0.43%	0.15%	0.32%	0.29%
Municipal Waste	0.04%	0.06%	0.10%	0.08%	0.10%
Emergency DR	0.05%	0.00%	0.00%	0.00%	0.00%

Figure 3-6 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 3-6 Type of fuel used (By real-time marginal units): January through September, 2004 through 2018

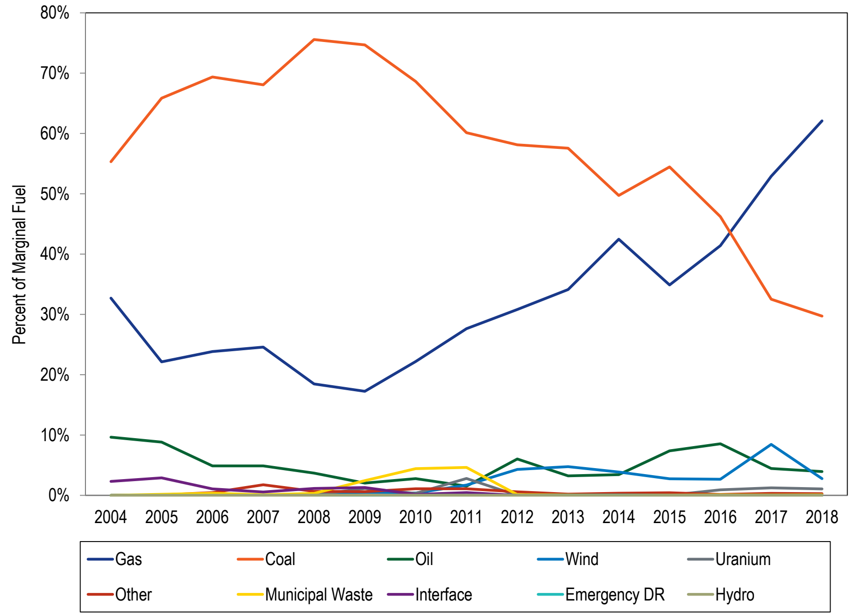


Table 3-9 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first nine months of 2018, up to congestion transactions were 63.9 percent of marginal resources. Up to congestion transactions were 80.4 percent of marginal resources in the first nine months of 2017.

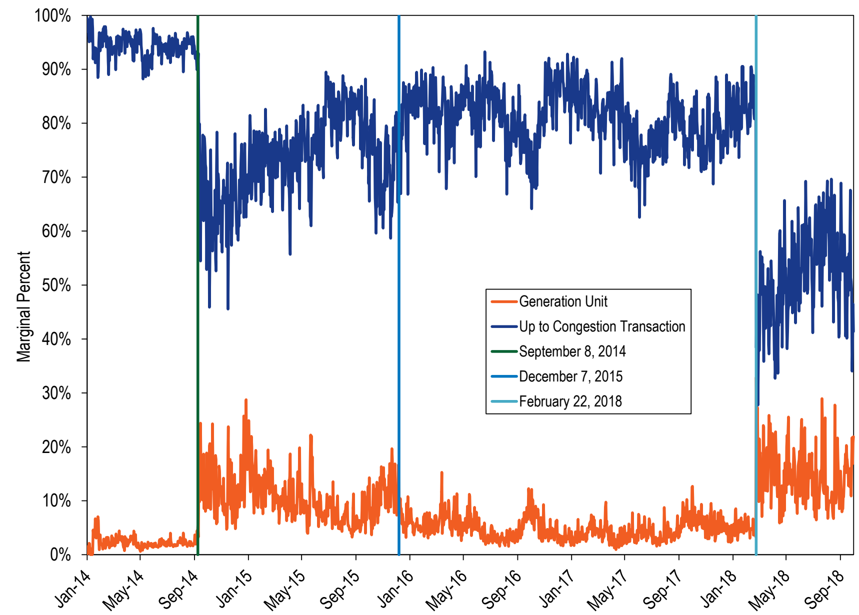
Table 3-9 Day-ahead marginal resources by type/fuel: January through September, 2011 through 2018

	(Jan - Sep)							
Type/Fuel	2011	2012	2013	2014	2015	2016	2017	2018
Up to Congestion Transaction	69.42%	86.73%	96.23%	93.69%	76.47%	81.88%	80.37%	63.90%
DEC	14.40%	5.15%	1.24%	2.19%	8.58%	8.89%	10.09%	16.06%
INC	8.44%	4.36%	1.01%	1.59%	4.94%	4.25%	5.53%	9.24%
Gas	1.78%	1.12%	0.44%	0.95%	3.20%	2.02%	1.83%	5.66%
Coal	5.36%	2.46%	0.97%	1.44%	6.08%	2.24%	1.71%	4.57%
Wind	0.07%	0.04%	0.04%	0.03%	0.14%	0.04%	0.17%	0.16%
Dispatchable Transaction	0.24%	0.07%	0.06%	0.08%	0.31%	0.05%	0.03%	0.13%
Uranium	0.00%	0.00%	0.00%	0.00%	0.00%	0.10%	0.06%	0.12%
Oil	0.00%	0.00%	0.00%	0.02%	0.21%	0.52%	0.19%	0.11%
Other	0.00%	0.00%	0.00%	0.00%	0.02%	0.01%	0.00%	0.04%
Price Sensitive Demand	0.28%	0.05%	0.01%	0.01%	0.03%	0.00%	0.00%	0.02%
Hydro	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%
Municipal Waste	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Figure 3-7 shows, for the Day-Ahead Energy Market from January 2014, through September 2018, the daily proportion of marginal resources that were up to congestion transaction and/or generation units. The percent of marginal up to congestion transactions (UTC) 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.[27] That trend reversed as a result of the expiration of the 15 month uplift refund period for UTC transactions. But in the first nine months of 2018, the percent of marginal up to congestion transactions again decreased significantly as the result of a FERC order issued on February 20, 2018 and implemented on February 22, 2018.[28] The order limited UTC trading to hubs, residual metered load, and interfaces. The share of marginal UTCs decreased from 79.1 percent in the period February 22, 2017, through September 30, 2017, to 50.7 percent in the period February 22, 2018, through September 30, 2018. The share of marginal generation resources increased from 4.0 percent in the period February 22, 2017, through September 30, 2017, to 14.5 percent in the period February 22, 2018, through September 30, 2018.

27 See 18 CFR § 385.213 (2014).
28 162 FERC ¶ 61,139 (2018).

Figure 3-7 Day-ahead marginal up to congestion transaction and generation units: January 2014 through September 2018



Supply

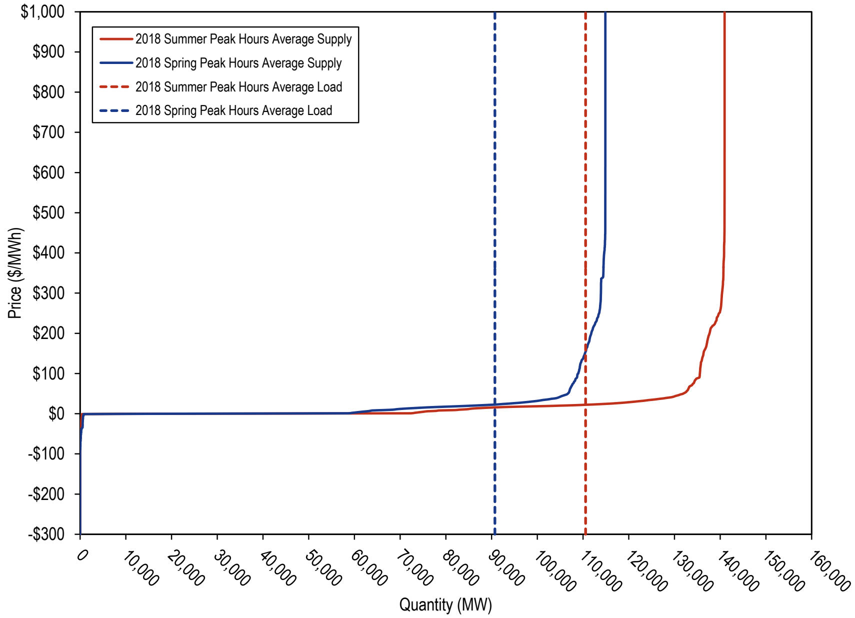
Supply includes physical generation, imports and virtual transactions.

In the first nine months of 2018, 7,945.4 MW of new resources were added and 4,894.2 MW were retired.

Figure 3-8 shows the average hourly real-time supply and load for the on peak hours of the spring and summer of 2018. This figure reflects actual available

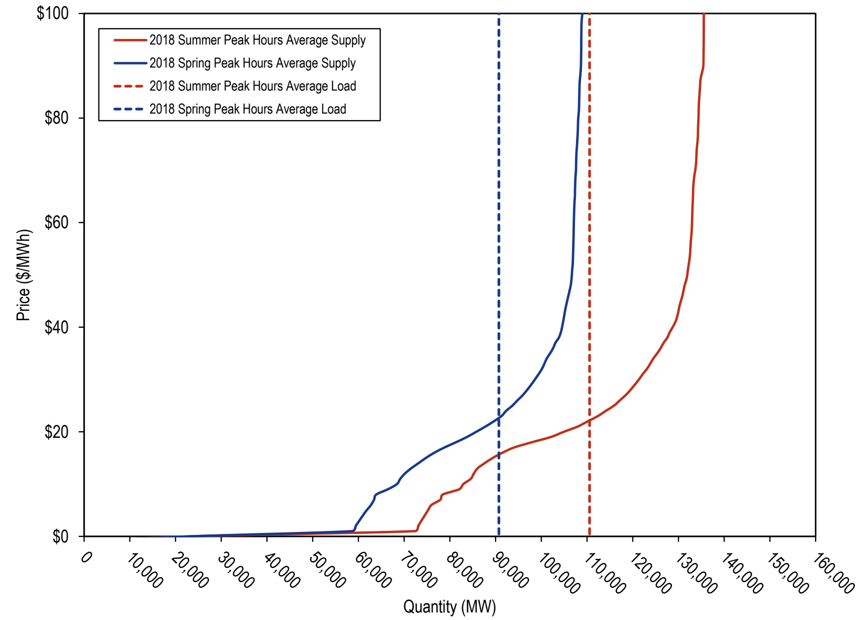
MW from units that are online or available to generate power in one hour including start-up and notification time, and restricted by the ramp limit.

Figure 3-8 Average hourly real-time supply curves: 2018 spring and summer[29]



Average hourly real-time supply curves are weather sensitive. Figure 3-9 shows the typical dispatch range curve.

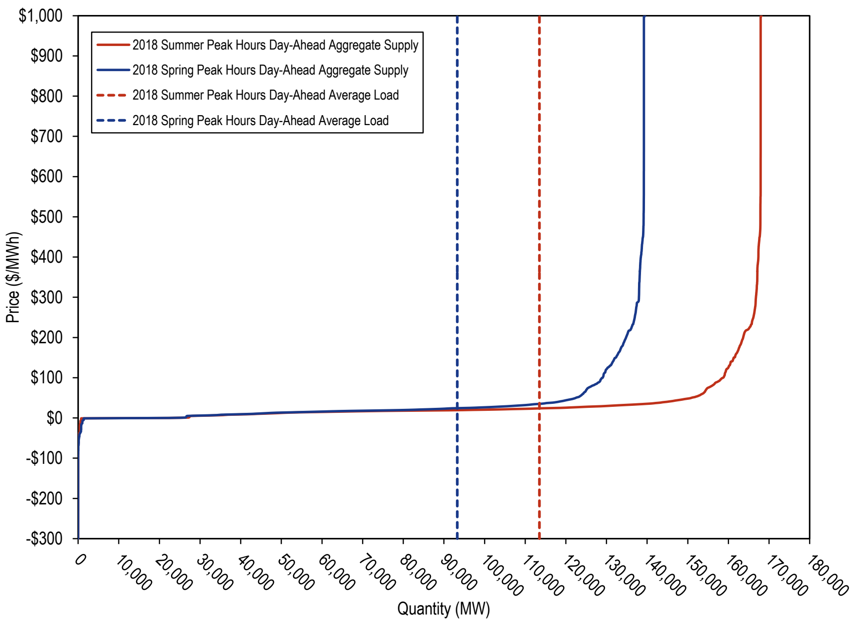
Figure 3-9 Typical dispatch range of average hourly real-time supply curves: 2018 spring and summer



29 Spring supply curve period is from March 1, 2018, to May 31, 2018. Summer supply curve period is from June 1, 2018 to August 31, 2018

Figure 3-10 is PJM day-ahead generation aggregate supply curve, which includes all day-ahead hourly offers for peak hours of the spring and summer of 2018.

Figure 3-10 PJM day-ahead generation aggregate supply curve: 2018 spring and summer



Energy Production by Fuel Source

Table 3-10 shows PJM generation by fuel source in GWh for the first nine months of 2017 and 2018. In the first nine months of 2018, generation from coal units decreased 5.2 percent, generation from natural gas units increased 19.4 percent, and generation from oil increased 83.9 percent compared to the first nine months of 2017.[30] The increase in gas-fired generation exceeded the increase in total generation, also offsetting decreases in coal and nuclear generation. Oil-fired generation increased, particularly during the first week of January 2018.

Table 3-10 Generation (By fuel source (GWh)): January through September, 2017 and 2018[31 32 33]

		2017 (Jan - Sep)		2018 (Jan - Sep)		Change in
		GWh	Percent	GWh	Percent	Output
Coal		195,983.6	32.2%	185,756.0	29.2%	(5.2%)
	Bituminous	169,207.1	27.8%	155,985.6	24.5%	(7.8%)
	Sub Bituminous	20,884.1	3.4%	23,582.9	3.7%	12.9%
	Other Coal	5,892.4	1.0%	6,187.4	1.0%	5.0%
Nuclear		215,089.3	35.3%	214,603.2	33.8%	(0.2%)
Gas		165,041.9	27.1%	196,583.1	30.9%	19.1%
	Natural Gas	163,206.8	26.8%	194,845.4	30.7%	19.4%
	Landfill Gas	1,821.7	0.3%	1,724.1	0.3%	(5.4%)
	Other Gas	13.4	0.0%	13.6	0.0%	1.3%
Hydroelectric		11,929.1	2.0%	14,190.8	2.2%	19.0%
	Pumped Storage	3,989.2	0.7%	4,497.7	0.7%	12.7%
	Run of River	6,633.4	1.1%	8,196.3	1.3%	23.6%
	Other Hydro	1,306.5	0.2%	1,496.9	0.2%	14.6%
Wind		14,268.3	2.3%	15,120.1	2.4%	6.0%
Waste		2,966.6	0.5%	3,356.8	0.5%	13.2%
	Solid Waste	2,764.2	0.5%	3,155.7	0.5%	14.2%
	Miscellaneous	202.4	0.0%	201.1	0.0%	(0.6%)
Oil		1,667.3	0.3%	3,066.6	0.5%	83.9%
	Heavy Oil	154.5	0.0%	435.1	0.1%	181.5%
	Light Oil	195.4	0.0%	899.9	0.1%	360.6%
	Diesel	24.8	0.0%	358.8	0.1%	1,349.8%
	Gasoline	0.0	0.0%	0.0	0.0%	NA
	Kerosene	1.2	0.0%	58.8	0.0%	4,884.7%
	Jet Oil	0.0	0.0%	8.0	0.0%	NA
	Other Oil	1,291.5	0.2%	1,306.0	0.2%	1.1%
Solar, Net Energy Metering		1,156.8	0.2%	1,709.5	0.3%	47.8%
Energy Storage		20.5	0.0%	10.6	0.0%	(48.5%)
	Battery	20.5	0.0%	10.6	0.0%	(48.5%)
	Compressed Air	0.0	0.0%	0.0	0.0%	NA
Biofuel		1,161.5	0.2%	1,306.6	0.2%	12.5%
Geothermal		0.0	0.0%	0.0	0.0%	NA
Other Fuel Type		0.0	0.0%	0.0	0.0%	NA
Total		609,284.8	100.0%	635,703.1	100.0%	4.3%

30 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.

31 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.
32 Net Energy Metering is combined with Solar due to data confidentiality reasons.
33 Other Gas includes: Propane, Butane, Hydrogen, Gasified Coal, and Refinery Gas.

Table 3-11 Monthly generation (By fuel source (GWh)): January through September, 2018

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Coal	27,514.6	18,362.3	19,734.7	16,225.5	17,690.3	20,391.4	23,679.9	24,251.4	17,905.8	185,756.0
Bituminous	23,012.8	15,782.6	16,374.3	13,731.6	15,089.2	16,893.9	19,973.4	20,393.5	14,734.3	155,985.6
Sub Bituminous	3,544.9	1,876.0	2,571.7	1,983.3	2,180.8	2,850.0	2,930.4	3,098.3	2,547.4	23,582.9
Other Coal	956.9	703.7	788.7	510.6	420.2	647.5	776.1	759.6	624.1	6,187.4
Nuclear	26,301.0	22,971.9	22,554.2	20,630.7	24,040.7	24,681.3	25,265.5	24,912.7	23,245.2	214,603.2
Gas	18,503.1	17,732.1	20,075.1	17,485.3	19,318.7	22,028.6	27,463.3	28,412.6	25,564.1	196,583.1
Natural Gas	18,303.6	17,543.4	19,869.9	17,294.7	19,126.2	21,845.5	27,270.6	28,222.9	25,368.6	194,845.4
Landfill Gas	199.5	188.7	205.2	190.6	192.6	182.8	190.1	189.8	184.8	1,724.1
Other Gas	0.0	0.0	0.0	0.0	0.0	0.3	2.6	0.0	10.7	13.6
Hydroelectric	1,194.4	1,301.4	1,354.2	1,526.9	1,797.3	1,623.8	1,605.3	2,045.6	1,742.1	14,190.8
Pumped Storage	384.8	324.9	388.4	402.2	480.5	602.0	665.4	724.1	525.3	4,497.7
Run of River	685.7	879.0	865.0	987.7	1,151.5	795.6	700.1	1,079.7	1,052.0	8,196.3
Other Hydro	123.8	97.4	100.8	137.1	165.2	226.3	239.8	241.8	164.8	1,496.9
Wind	2,857.3	2,149.0	2,389.0	2,045.6	1,521.3	1,119.4	883.8	987.5	1,167.2	15,120.1
Waste	378.8	351.9	367.1	352.5	364.2	394.2	400.0	409.1	339.1	3,356.8
Solid Waste	354.3	329.2	341.9	329.3	345.6	371.9	378.3	387.2	317.9	3,155.7
Miscellaneous	24.5	22.7	25.2	23.1	18.6	22.3	21.7	21.8	21.2	201.1
Oil	1,538.4	155.3	123.3	196.6	233.7	282.3	185.5	196.8	154.7	3,066.6
Heavy Oil	257.0	0.0	0.0	0.0	32.6	138.5	6.0	1.0	0.0	435.1
Light Oil	728.0	11.8	6.8	37.5	33.6	7.8	17.9	32.0	24.4	899.9
Diesel	330.5	0.7	1.7	4.9	7.0	5.8	6.3	1.3	0.8	358.8
Gasoline	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kerosene	55.6	0.0	0.0	0.9	0.0	0.0	2.2	0.0	0.1	58.8
Jet Oil	8.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.0
Other Oil	159.3	142.9	114.9	153.3	160.5	130.2	153.1	162.5	129.3	1,306.0
Solar, Net Energy Metering	113.6	100.6	177.0	220.5	221.9	242.6	241.9	236.7	154.7	1,709.5
Energy Storage	1.4	1.0	1.4	1.4	1.3	1.2	1.1	0.9	1.0	10.6
Battery	1.4	1.0	1.4	1.4	1.3	1.2	1.1	0.9	1.0	10.6
Compressed Air	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biofuel	170.3	129.9	160.3	110.4	145.3	160.6	162.3	147.7	119.8	1,306.6
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fuel Type	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	78,572.9	63,255.5	66,936.2	58,795.3	65,334.5	70,925.6	79,888.6	81,600.8	70,393.7	635,703.1

Generator Offers

Generator offers are categorized as dispatchable (Table 3-12) or self scheduled (Table 3-13).[34] 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 3-12 and Table 3-13 do not include units that did not indicate their offer status or 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 3-12 shows the proportion of day-ahead MW offered by dispatchable units, by unit type and by offer price range, in the first nine months of 2018. For example, 41.7 percent of all CC offers were the economic minimum offered MW and 27.4 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, 79.1 percent of all CC MW offers were dispatchable, including the 4.4 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, 17.7 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 2018, 23.3 percent were offered as available for economic dispatch, excluding emergency MW and economic minimum MW (57.9 percent less 4.8 and 29.8 percent).

34 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 3-12 Distribution of day-ahead MW for dispatchable unit offer prices: January through September, 2018

		Dispatchable (Range)							
Unit Type	Economic Minimum	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	41.7%	0.0%	27.4%	3.5%	1.3%	0.5%	0.3%	4.4%	79.1%
CT	66.5%	0.0%	17.4%	4.0%	2.1%	0.8%	0.2%	7.2%	98.1%
Diesel	40.7%	0.0%	11.4%	8.0%	0.4%	0.0%	0.0%	18.1%	78.6%
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	6.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.5%
Pumped Storage	0.0%	0.0%	8.3%	0.0%	0.0%	0.0%	0.0%	41.6%	49.9%
Run of River	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Solar	0.0%	0.0%	5.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.0%
Steam	21.9%	0.0%	24.0%	1.7%	0.1%	0.1%	0.2%	2.3%	50.4%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	3.2%	0.0%	11.0%	0.0%	0.0%	0.0%	0.0%	3.2%	17.5%
All Dispatchable Offers	29.8%	0.0%	17.7%	2.1%	0.7%	0.3%	0.2%	4.8%	57.9%

Table 3-13 Distribution of day-ahead MW for self scheduled and dispatchable unit offer prices: January through September, 2018

	Self Scheduled		Self Scheduled and Dispatchable (Range)								
Unit Type	Must Run	Emergency	Economic Minimum	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	1.4%	0.3%	10.4%	0.0%	6.2%	1.0%	0.3%	0.2%	0.0%	0.9%	20.8%
CT	0.2%	0.1%	1.0%	0.0%	0.5%	0.0%	0.0%	0.0%	0.0%	0.1%	1.9%
Diesel	17.1%	0.3%	1.1%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	18.7%
Fuel Cell	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Nuclear	70.0%	0.0%	18.7%	0.0%	1.7%	0.0%	0.0%	0.0%	0.0%	0.0%	90.5%
Pumped Storage	3.4%	4.5%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	8.2%
Run of River	87.2%	3.1%	1.7%	0.0%	7.6%	0.0%	0.0%	0.0%	0.0%	0.0%	99.5%
Solar	21.1%	4.0%	0.0%	0.0%	0.9%	0.0%	0.0%	0.0%	0.0%	0.0%	26.1%
Steam	4.2%	1.1%	21.9%	0.0%	20.5%	0.1%	0.0%	0.1%	0.0%	1.4%	49.4%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	7.4%	7.4%	4.1%	0.0%	1.1%	0.0%	0.0%	0.0%	0.0%	4.1%	24.0%
All Self-Scheduled Offers	16.7%	0.8%	13.6%	0.0%	8.7%	0.3%	0.1%	0.1%	0.0%	0.8%	42.1%

Table 3-13 shows the proportion of day-ahead 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 2018. For example, 10.4 percent of CC offers were the economic minimum and 6.2 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, 20.8 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 0.9 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 16.7 percent of all offers and self scheduled and dispatchable units accounted for 17.5 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 2018, 17.5 percent were offered as self scheduled and 23.5 percent were offered as self scheduled and dispatchable.

Fuel Diversity

Figure 3-11 shows the fuel diversity index (FDI_e) for PJM energy generation.[35] 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 results 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 3-11 with nonzero generation values. As fuel diversity has increased, seasonality in the

35 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.

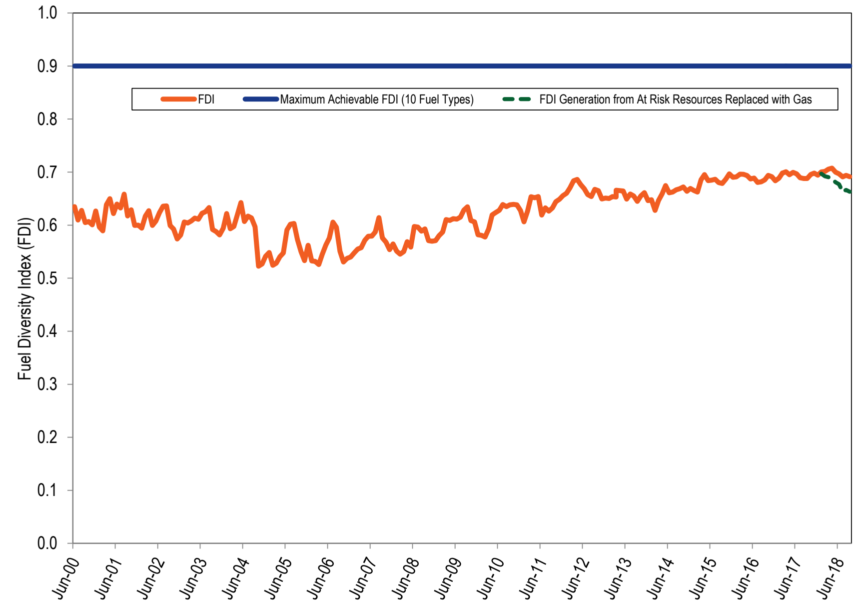
FDI_e has decreased and the FDI_e has exhibited less volatility. Since 2012, the monthly FDI_e has been less volatile as a result of the decline in the share of coal from 51.3 percent prior to 2012 to 37.6 percent from 2012 through the first nine months of 2018. A significant drop in the FDI_e occurred 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.[36] The increasing trend that began in 2008 is a result of decreasing coal generation, increasing gas generation and increasing wind generation. Coal generation as a share of total generation was 55.0 percent for the first nine months of 2008 and 29.2 percent for the first nine months of 2018, a decrease of 25.8 percentage points. Gas generation as a share of total generation was 7.7 percent for the first nine months of 2008 and 30.9 percent for the first nine months of 2018, an increase of 23.2 percentage points. Wind generation as a share of total generation was 0.4 percent for the first nine months of 2008 and 2.4 percent for the first nine months of 2018, an increase of 2.0 percentage points.

The average FDI_e increased 0.7 percent in the first nine months of 2018 compared to the first nine months of 2017. The FDI_e was also used to measure the impact on fuel diversity of potential retirements by resources that have been identified as at risk of retirement by the MMU's net revenue adequacy analysis.[37] There were 113 units with installed capacity totaling 25.0 GW identified as being at risk of retirement. The 113 at risk resources generated 70.0 GWh in the first nine months of 2018, with 68.3 GWh from coal, nuclear and oil fired generators. The dashed line in Figure 3-11 shows the FDI_e calculated assuming that this 68.3 GWh of generation from at risk resources, were replaced by gas generation. The FDI_e under these assumptions would have decreased in each of the nine months with an average monthly decrease of 2.7 percent compared to the actual FDI_e.

36 See the *2017 State of the Market Report for PJM*, Volume 2, 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.

37 See the *2017 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Units at Risk.

Figure 3-11 Fuel diversity index for monthly generation: June 2000 through September 2018



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 on-peak hour offered real-time supply was 114,869 MWh for spring of 2018, and 140,951 MWh for summer of 2018.

PJM average real-time cleared generation in the first nine months of 2018 increased by 4.3 percent from the first nine months of 2017, from 91,658 MWh to 95,561 MWh.[38]

PJM average, real-time cleared supply, including imports in the first nine months of 2018 increased by 4.2 percent from the first nine months 2017, from 93,639 MWh to 97,588 MWh.

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

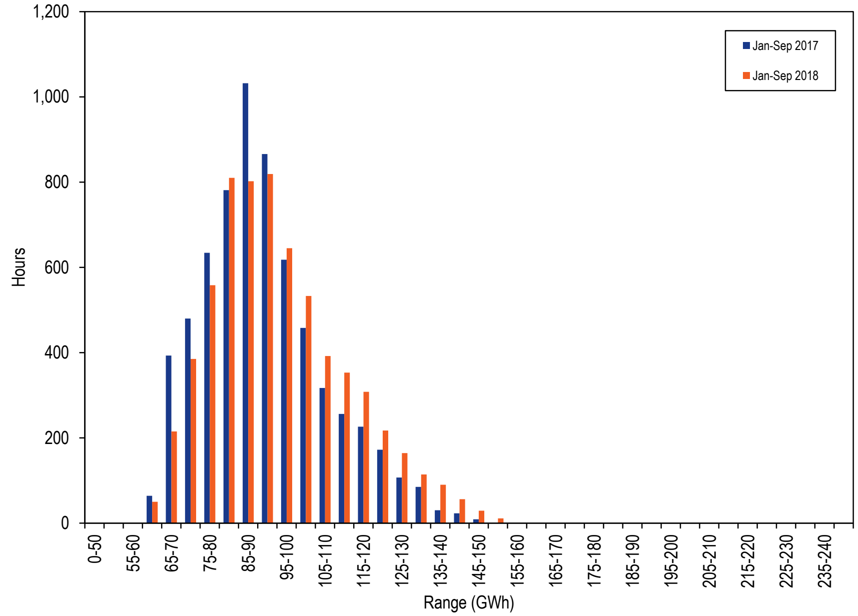
- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a specific unit.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. A real-time import must have a valid OASIS reservation when offered, must have available ramp room to support the import, must be accompanied by a NERC Tag, and must pass the neighboring balancing authority checkout process.

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

PJM Real-Time Supply Duration

Figure 3-12 shows the hourly distribution of PJM real-time generation plus imports for the first nine months of 2017 and 2018.

Figure 3-12 Distribution of real-time generation plus imports: January through September, 2017 and 2018[39]



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

PJM Real-Time, Average Supply

Table 3-14 presents summary average real-time hourly supply statistics for each year for the first nine months of 18-year period from 2001 through 2018.

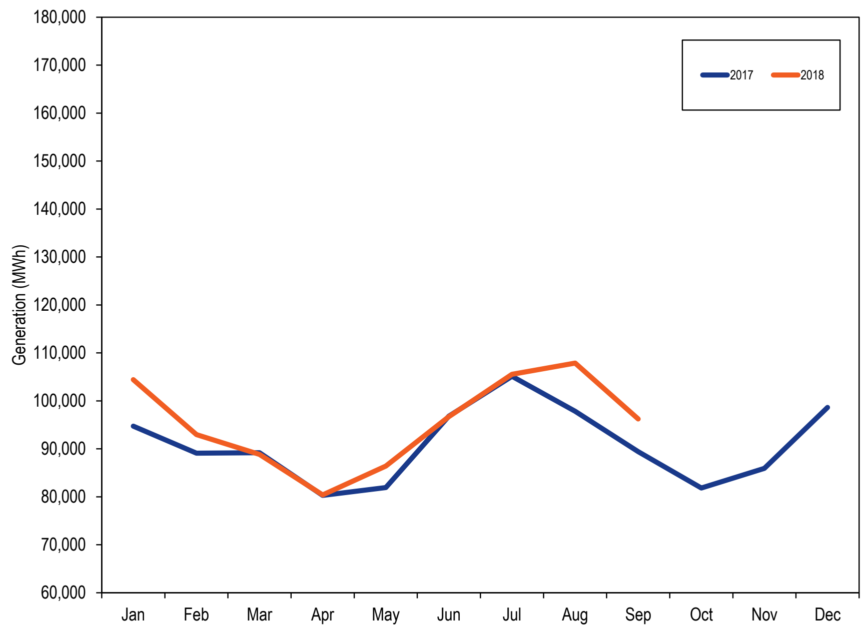
Table 3-14 Real-time generation and real-time generation plus imports: January through September, 2001 through 2018

	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	93,639	16,216	(1.2%)	(16.0%)	(3.4%)	(15.0%)
2018	95,561	17,506	97,588	17,747	4.3%	9.7%	4.2%	9.4%

PJM Real-Time, Monthly Average Generation

Figure 3-13 compares the real-time, monthly average hourly generation in 2017 and the first nine months of 2018

Figure 3-13 Real-time monthly average hourly generation: January 2017 through September 2018



Day-Ahead Supply

PJM average, day-ahead cleared supply in the first nine months of 2018, including INCs and up to congestion transactions, decreased by 13.0 percent from the first nine months of 2017, from 133,377 MWh to 116,068 MWh.

PJM average, day-ahead cleared supply in the first nine months of 2018, including INCs, up to congestion transactions, and imports, decreased by 13.1 percent from the first nine months of 2017, from 134,000 MWh to 116,471 MWh.

The significant decrease in up to congestion transactions (UTC) is a result of the reduction in the number of UTC trading points as directed in the FERC order issued February 20, 2018.[40]

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

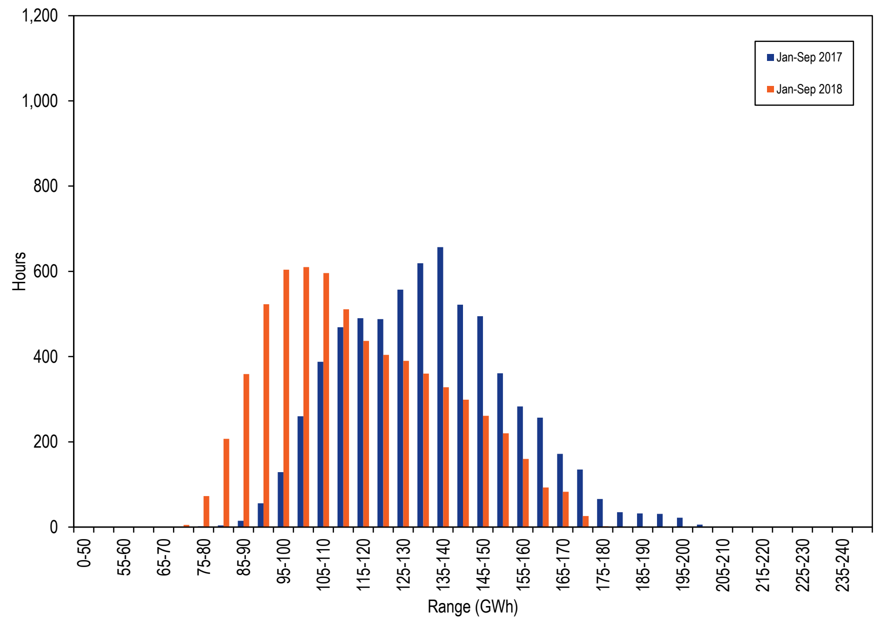
- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a unit.
- **Increment Offer (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.

40 162 FERC ¶ 61,139.

PJM Day-Ahead Supply Duration

Figure 3-14 shows the hourly distribution of PJM day-ahead supply, including increment offers, up to congestion transactions, and imports for first nine months of 2017 and 2018.

Figure 3-14 Distribution of day-ahead supply plus imports: January through September, 2017 and 2018[41]



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

PJM Day-Ahead, Average Supply

Table 3-15 presents summary average day-ahead hourly supply statistics for the first nine months of 18-year period from 2001 through 2018.

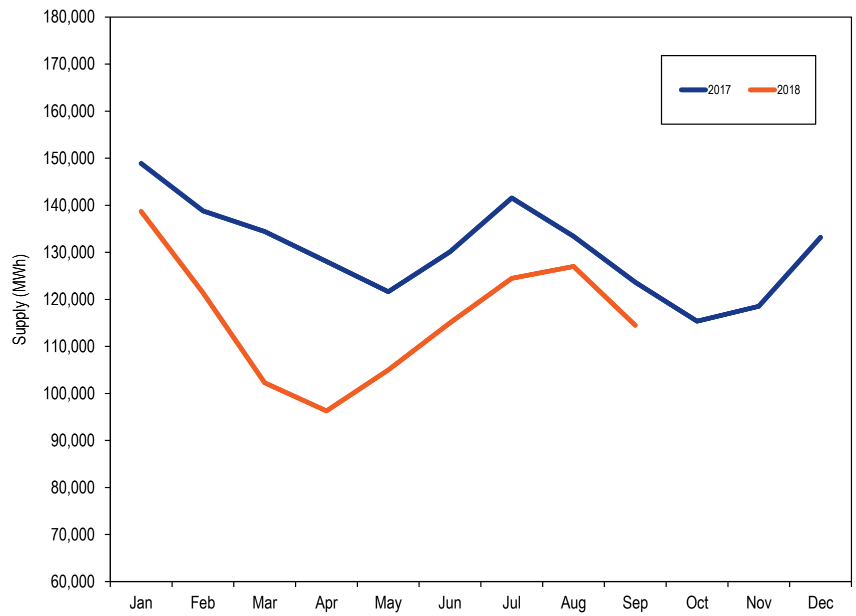
Table 3-15 Day-ahead supply and day-ahead supply plus imports: January through September, 2001 through 2018

	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	134,000	20,710	0.2%	(12.0%)	(0.7%)	(11.5%)
2018	116,068	21,950	116,471	21,939	(13.0%)	6.5%	(13.1%)	5.9%

PJM Day-Ahead, Monthly Average Supply

Figure 3-15 compares the day-ahead, monthly average hourly supply, including increment offers and up to congestion transactions for 2017 and first nine months of 2018.

Figure 3-15 Day-ahead monthly average hourly supply: January 2017 through September 2018



Real-Time and Day-Ahead Supply

Table 3-16 presents summary statistics for the first nine months of 2017 and 2018, for day-ahead and real-time supply. All data are cleared MWh. The last two columns of Table 3-16 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 2018, up to congestion transactions were 15.1 percent of the total day-ahead supply compared to 27.2 percent in the first nine months of 2017. The nearly fifty percent reduction in UTCs clearing in the day-ahead market directly resulted in an increase in the amount of physical generation clearing in the day-ahead market. While day-ahead generation and total supply still exceed real-time generation and total supply, the difference is smaller.

Table 3-16 Day-ahead and real-time supply (MWh): January through September, 2017 and 2018

		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	2017	92,035	4,876	36,467	623	134,000	91,658	93,639	40,362	376
	2018	95,852	2,577	17,639	403	116,471	95,561	97,588	18,883	291
Median	2017	90,180	4,844	36,007	381	133,520	89,480	91,464	42,057	700
	2018	93,293	2,470	15,754	362	112,889	92,551	94,608	18,281	742
Standard Deviation	2017	16,644	1,498	8,567	535	20,710	15,964	16,216	4,494	680
	2018	17,680	1,084	8,143	246	21,939	17,506	17,747	4,192	174
Peak Average	2017	101,879	5,288	38,950	583	146,700	100,803	102,946	43,755	1,076
	2018	105,389	3,137	18,713	383	127,622	104,480	106,732	20,891	910
Peak Median	2017	98,249	5,244	38,586	311	144,701	97,021	99,638	45,063	1,228
	2018	102,804	3,108	16,630	333	126,398	101,231	103,411	22,988	1,573
Peak Standard Deviation	2017	14,067	1,473	8,335	528	16,580	14,160	14,284	2,296	(93)
	2018	15,532	1,086	8,633	266	19,750	15,968	15,996	3,754	(436)
Off-Peak Average	2017	83,427	4,516	34,295	658	122,895	83,662	85,501	37,395	(235)
	2018	87,512	2,088	16,700	420	106,720	87,762	89,592	17,128	(250)
Off-Peak Median	2017	81,430	4,508	33,484	400	120,369	81,413	83,195	37,174	17
	2018	84,670	2,020	14,967	380	102,006	84,785	86,452	15,554	(115)
Off-Peak Standard Deviation	2017	13,689	1,425	8,170	539	17,299	12,858	13,136	4,163	831
	2018	15,030	811	7,566	225	18,904	14,872	15,153	3,752	158

Figure 3-16 shows the average hourly cleared volumes of day-ahead supply and real-time supply for the first nine months of 2018. 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 3-16 Day-ahead and real-time supply (Average hourly volumes): January through September, 2018

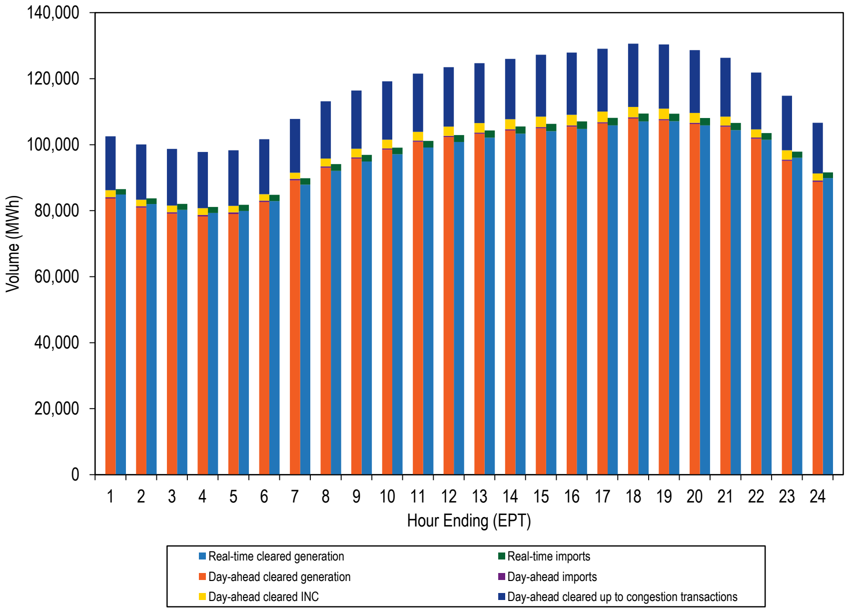


Figure 3-17 shows the difference between the day-ahead and real-time average daily supply for 2017 and the first nine months of 2018.

Figure 3-17 Difference between day-ahead and real-time supply (Average daily volumes): January 2017 through September 2018

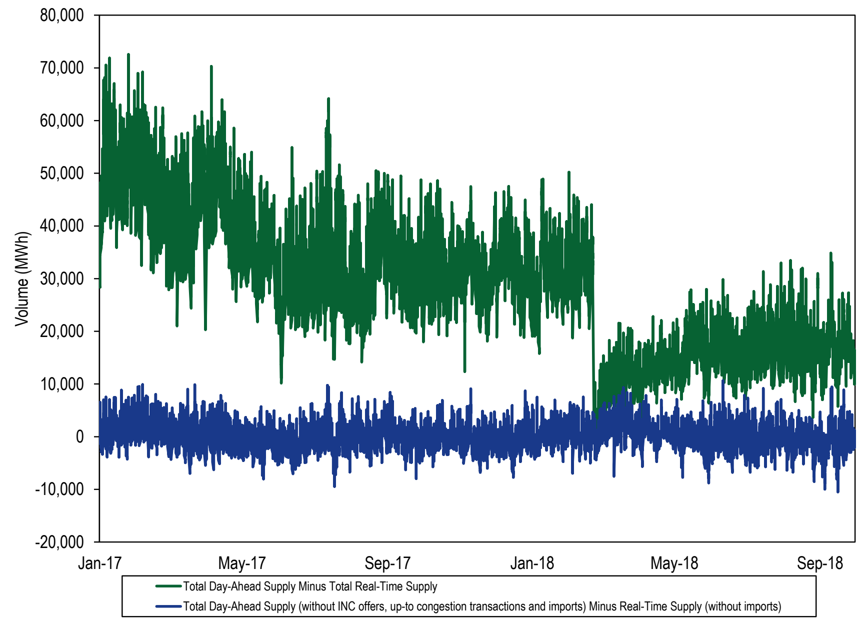
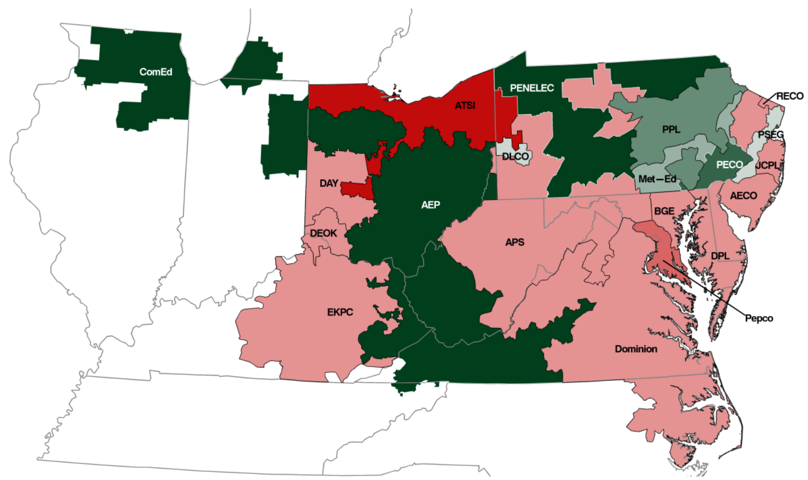


Figure 3-18 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2018. Figure 3-18 is color coded using a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation 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 3-17 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2017 and 2018.

Figure 3-18 Map of real-time generation, less real-time load, by zone: January through September, 2018[42]



Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)
AECO	(3,625)	ComEd	25,724	DPL	(9,321)	PENELEC	19,980
AEP	25,755	DAY	(8,769)	EKPC	(2,963)	Pepco	(13,669)
APS	(1,915)	DEOK	(7,742)	JCPL	(4,762)	PPL	11,075
ATSI	(21,962)	DLCO	1,589	Met-Ed	5,343	PSEG	1,770
BGE	(7,982)	Dominion	(2,976)	PECO	19,548	RECO	(1,153)

Table 3-17 Real-time generation less real-time load by zone (GWh): January through September, 2017 and 2018

	Zonal Generation and Load (GWh)					
	2017 (Jan - Sep)			2018 (Jan - Sep)		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	4,899.3	7,499.2	(2,599.9)	4,242.8	7,867.9	(3,625.1)
AEP	114,163.5	92,453.7	21,709.8	123,589.1	97,834.0	25,755.1
APS	34,647.6	35,171.9	(524.3)	35,587.8	37,502.7	(1,914.8)
ATSI	30,025.8	49,178.0	(19,152.2)	29,389.7	51,351.5	(21,961.9)
BGE	14,772.8	22,889.4	(8,116.6)	16,196.6	24,178.2	(7,981.6)
ComEd	95,716.8	71,484.1	24,232.7	100,500.7	74,776.7	25,724.0
DAY	8,697.8	12,614.6	(3,916.7)	4,504.3	13,273.5	(8,769.2)
DEOK	15,071.4	19,873.9	(4,802.5)	13,325.7	21,067.3	(7,741.6)
DLCO	12,320.7	10,143.4	2,177.2	12,211.4	10,622.5	1,588.9
Dominion	70,692.7	71,915.3	(1,222.7)	73,760.9	76,737.1	(2,976.1)
DPL	5,847.9	13,446.0	(7,598.1)	5,052.2	14,373.1	(9,321.0)
EKPC	5,822.5	9,027.8	(3,205.3)	7,007.3	9,970.2	(2,962.8)
JCPL	14,184.4	16,853.2	(2,668.9)	12,900.4	17,662.1	(4,761.7)
Met-Ed	16,578.8	11,288.2	5,290.6	17,255.1	11,911.8	5,343.3
PECO	48,514.8	29,768.2	18,746.6	50,623.4	31,075.1	19,548.3
PENELEC	32,814.0	12,474.7	20,339.4	32,966.8	12,986.4	19,980.4
Pepco	6,383.8	22,198.1	(15,814.3)	9,471.3	23,140.5	(13,669.2)
PPL	35,461.3	29,544.3	5,916.9	41,907.0	30,831.8	11,075.2
PSEG	33,838.1	32,605.8	1,232.3	35,525.9	33,755.6	1,770.3
RECO	0.0	1,095.6	(1,095.6)	0.0	1,152.6	(1,152.6)

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.[43]

The PJM system real-time peak load in the first nine months of 2018 was 147,042 MWh in the HE 1700 on August 28, 2018, which was 4,656 MWh, or 3.3 percent, higher than the peak load in the first nine months of 2017, which was 142,387 MWh in the HE 1800 on July 19, 2017.

42 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>.

43 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 on PJM Manual 19: Load Forecasting and Analysis," Attachment A: Load Drop Estimate Guidelines at <http://www.pjm.com/~/media/documents/manuals/m19.ashx>.

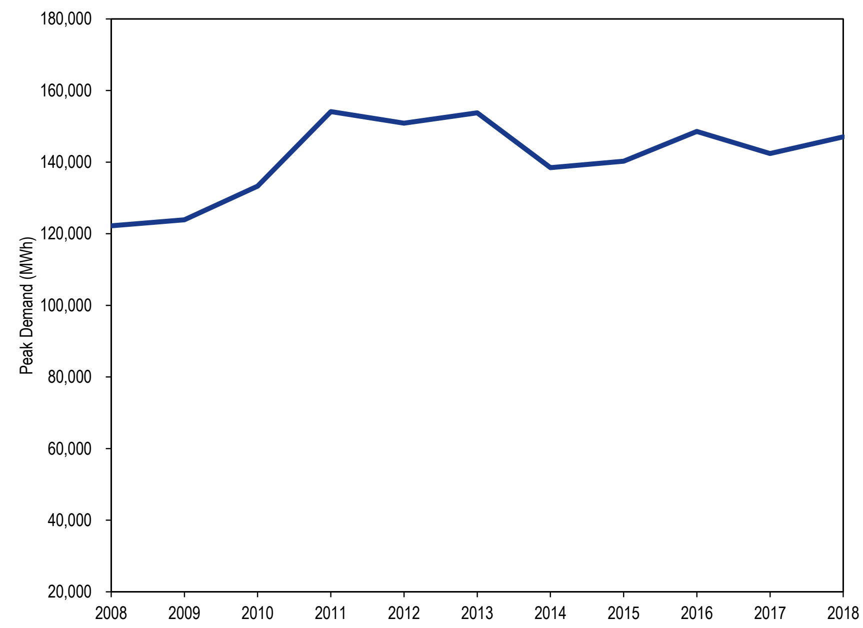
Table 3-18 shows the peak loads for the first nine months of 2008 through 2018.

Table 3-18 Actual footprint peak loads: January through September, 2008 to 2018[44 45]

(Jan - Sep)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
2008	Fri, August 01	17	122,215	NA	NA
2009	Mon, August 10	17	123,900	1,686	1.4%
2010	Tue, July 06	17	133,297	9,397	7.6%
2011	Thu, July 21	17	154,095	20,798	15.6%
2012	Tue, July 17	17	150,879	(3,216)	(2.1%)
2013	Thu, July 18	17	153,790	2,911	1.9%
2014	Tue, June 17	18	138,448	(15,341)	(10.0%)
2015	Tue, July 28	17	140,266	1,818	1.3%
2016	Thu, August 11	16	148,577	8,311	5.9%
2017	Wed, July 19	18	142,387	(6,190)	(4.2%)
2018	Tue, August 28	17	147,042	4,656	3.3%

Figure 3-19 shows the peak loads for the first nine months of 2008 through 2018.

Figure 3-19 Footprint calendar year peak loads: January through September, 2008 to 2018

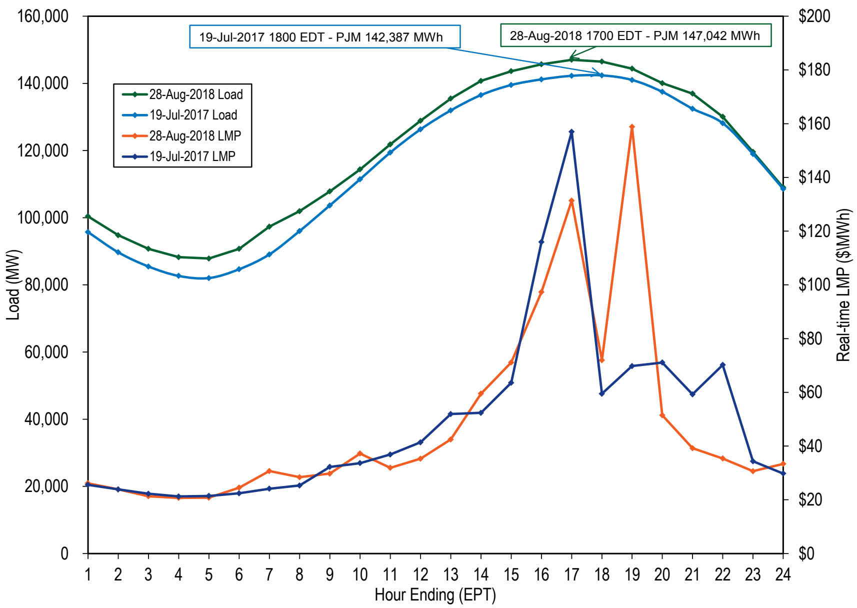


44 Peak loads shown are Power accounting load. See the *MMU Technical Reference for the PJM Markets*, at "Load Definitions" for detailed definitions of load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

45 Peak loads shown have been corrected to reflect the accounting load value excluding PJM loss adjustment. The values presented in this table do not include settlement adjustments made prior to January 1, 2017.

Figure 3-20 compares the peak load days during the first nine months of 2017 and 2018. The average real-time LMP for the August 28, 2018 peak load hour was $131.36 and for the July 19, 2017 peak load hour was $59.49.

Figure 3-20 Peak-load comparison Wednesday, July 19, 2017 and Tuesday, August 28, 2018



Real-Time Demand

PJM average real-time demand in the first nine months of 2018 increased by 5.5 percent from the first nine months of 2017, from 87,243 MWh to 92,047 MWh.[46]

PJM average real-time demand including exports in the first nine months of 2018 increased by 4.2 percent from the first nine months of 2017, from 91,954 MWh to 95,817 MWh.

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

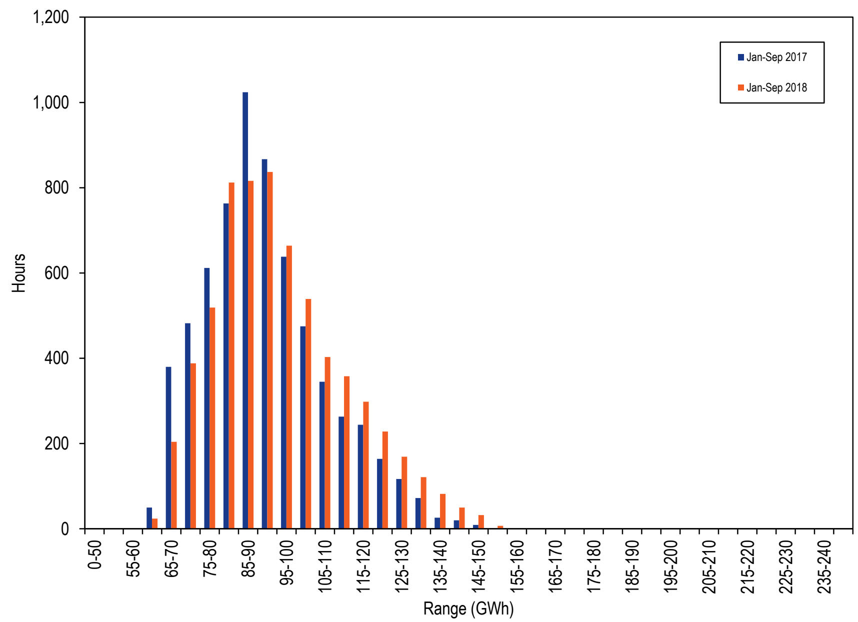
In the PJM Real-Time Energy Market, there are two types of demand:

- **Load.** The actual MWh level of energy used 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's checkout process.

PJM Real-Time Demand Duration

Figure 3-21 shows the hourly distribution of PJM real-time load plus exports for the first nine months of 2017 and 2018.[47]

Figure 3-21 Distribution of real-time accounting load plus exports: January through September, 2017 and 2018[48]



47 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>.
48 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Real-Time, Average Load

Table 3-19 presents summary average real-time hourly demand statistics for the first nine months of 2001 to 2018. 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.[49]

Table 3-19 Real-time load and real-time load plus exports: January through September, 2001 through 2018

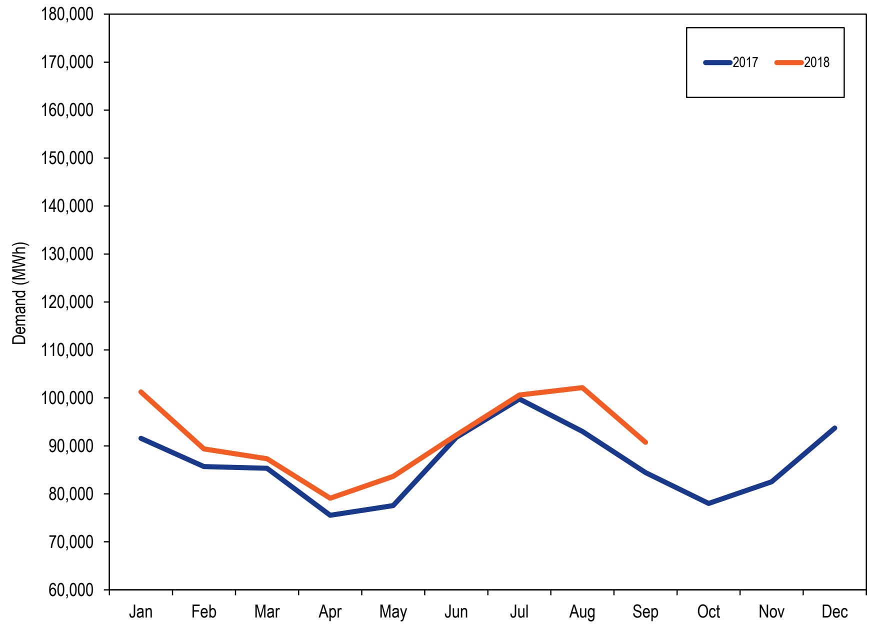
	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Jan-Sep	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
2001	31,060	6,156	32,900	5,861	NA	NA	NA	NA
2002	35,715	8,688	37,367	8,878	15.0%	41.1%	13.6%	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	91,954	15,794	(3.7%)	(12.0%)	(3.6%)	(15.0%)
2018	92,047	16,874	95,817	17,071	5.5%	5.4%	4.2%	8.1%

49 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.

PJM Real-Time, Monthly Average Load

Figure 3-22 compares the real-time, monthly average hourly loads for 2017 and the first nine months of 2018.

Figure 3-22 Real-time monthly average hourly load: January 2017 through September 2018



PJM real-time load is significantly affected by temperature. Figure 3-23 and Table 3-20 compare the PJM monthly heating and cooling degree days in 2017 and the first nine months of 2018.[50] Heating degree days decreased 23.5 percent from the first nine months of 2017 to 2018.

50 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 3-23 Heating and cooling degree days: January 2017 through September 2018

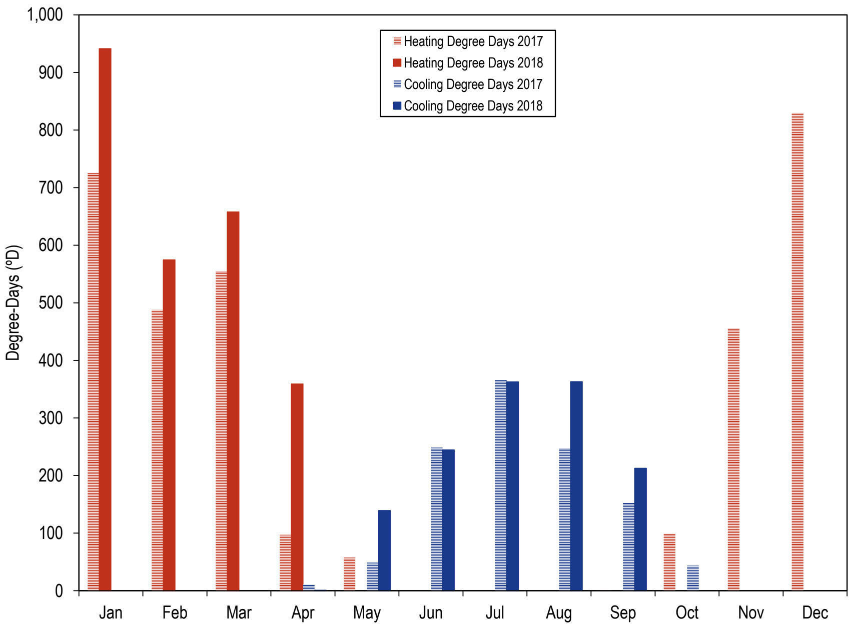


Table 3-20 Heating and cooling degree days: January 2017 through September 2018

	2017		2018		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	725	0	941	0	29.7%	0.0%
Feb	488	0	575	0	17.8%	0.0%
Mar	555	0	658	0	18.5%	0.0%
Apr	97	11	359	1	268.9%	(90.7%)
May	58	49	0	139	(100.0%)	184.6%
Jun	0	249	0	245	0.0%	(1.6%)
Jul	0	366	0	363	0.0%	(0.8%)
Aug	0	248	0	363	0.0%	46.6%
Sep	1	152	0	213	(100.0%)	39.5%
Oct	99	44				
Nov	456	0				
Dec	830	0				
Jan-Sep	1,924	1,074	2,532	1,324	(23.5%)	18.4%

Day-Ahead Demand

PJM average day-ahead demand in the first nine months of 2018, including DECs and up to congestion transactions, decreased by 13.1 percent from the first nine months of 2017, from 128,450 MWh to 111,589 MWh.

PJM average day-ahead demand in the first nine months of 2018, including DECs, up to congestion transactions, and exports, decreased by 13.1 percent from the first nine months of 2017, from 131,569 MWh to 114,373 MWh.

The significant decrease in up to congestion transactions (UTC) is a result of the reduction in the number of UTC trading points as directed in the FERC order issued February 20, 2018.[51]

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.

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.

51 162 FERC ¶ 61,139.

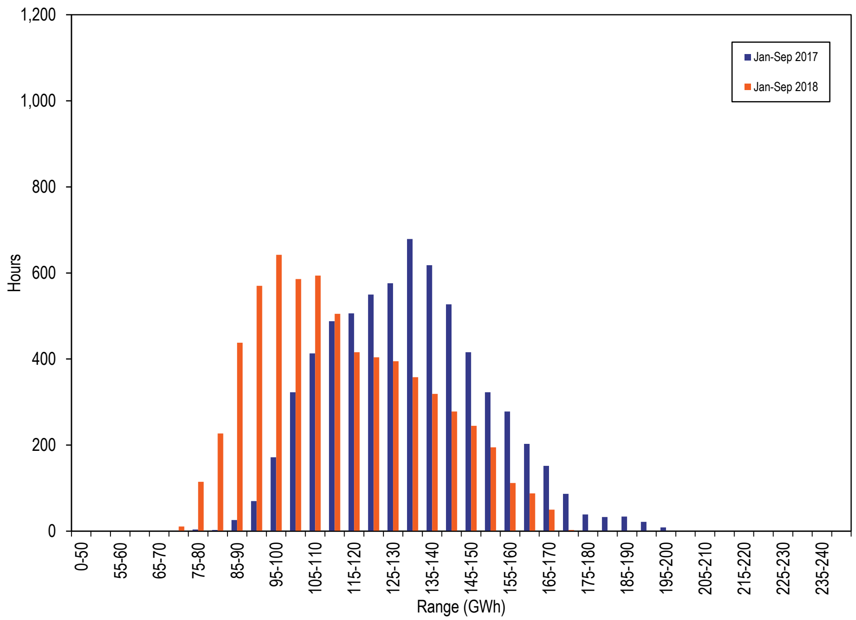
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A DEC can be submitted by any market 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 3-24 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up to congestion transactions, and exports for the first nine months of 2017 and 2018.

Figure 3-24 Distribution of day-ahead demand plus exports: January through September, 2017 and 2018[52]



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

PJM Day-Ahead, Average Demand

Table 3-21 presents summary average day-ahead hourly demand statistics for the first nine months of each year from 2001 to 2018.

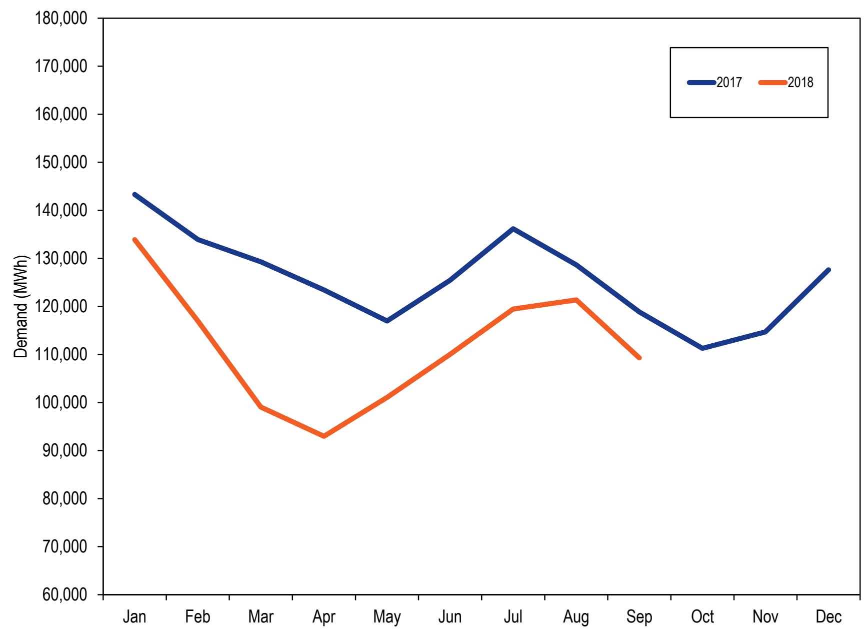
Table 3-21 Day-ahead demand and day-ahead demand plus exports: January through September, 2001 through 2018

	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	131,569	20,158	(0.5%)	(11.1%)	(0.8%)	(11.7%)
2018	111,589	21,194	114,373	21,392	(13.1%)	6.0%	(13.1%)	6.1%

PJM Day-Ahead, Monthly Average Demand

Figure 3-25 compares the day-ahead, monthly average hourly demand, including decrement bids and up to congestion transactions in 2017 and the first nine months of 2018.

Figure 3-25 Day-ahead monthly average hourly demand: January 2017 through September 2018



Real-Time and Day-Ahead Demand

Table 3-22 presents summary statistics for the first nine months of 2017 and 2018 day-ahead and real-time demand. All data are cleared MW. The last two columns of Table 3-22 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 3-22 Cleared day-ahead and real-time demand (MWh): January through September, 2017 and 2018

		Day-Ahead						Real-Time		Day-Ahead Less Real-Time	
Jan-Sep	Year	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Total Demand	Total Load
Average	2017	84,661	2,925	4,397	36,467	3,119	131,569	87,243	91,954	39,615	47,628
	2018	88,840	2,258	2,851	17,639	2,784	114,373	91,905	95,795	18,578	73,328
Median	2017	82,853	2,901	4,383	36,007	3,049	131,132	85,019	89,837	41,295	43,724
	2018	86,670	2,296	2,539	15,754	2,687	110,917	89,193	92,919	17,998	71,195
Standard Deviation	2017	15,347	437	1,282	8,567	996	20,158	16,008	15,794	4,365	11,643
	2018	16,252	570	1,413	8,143	933	21,392	17,064	17,245	4,148	12,916
Peak Average	2017	93,973	3,207	4,687	38,950	3,163	143,980	96,405	101,043	42,937	53,468
	2018	98,048	2,490	3,176	18,713	2,837	125,263	100,932	104,723	20,541	80,391
Peak Median	2017	91,266	3,139	4,687	38,586	3,110	141,992	93,100	97,873	44,119	48,981
	2018	95,515	2,687	2,927	16,630	2,716	124,075	97,793	101,406	22,669	75,124
Peak Standard Deviation	2017	13,019	390	1,195	8,335	1,059	16,132	14,095	13,891	2,242	11,854
	2018	13,911	552	1,386	8,633	925	19,250	15,023	15,534	3,717	11,306
Off-Peak Average	2017	76,519	2,679	4,143	34,295	3,081	120,717	79,231	84,007	36,710	42,520
	2018	80,789	2,056	2,567	16,700	2,738	104,850	84,013	87,989	16,861	67,152
Off-Peak Median	2017	74,470	2,624	4,012	33,484	3,022	118,288	76,942	81,792	36,496	40,446
	2018	78,412	2,210	2,211	14,967	2,672	100,275	81,210	85,003	15,272	65,938
Off-Peak Standard Deviation	2017	12,296	309	1,301	8,170	936	16,784	13,000	12,786	3,999	9,002
	2018	13,673	505	1,376	7,566	937	18,423	14,661	14,691	3,732	10,929

Figure 3-26 shows the average hourly cleared volumes of day-ahead demand and real-time demand for the first nine months of 2018. 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 3-26 Day-ahead and real-time demand (Average hourly volumes): January through September, 2018

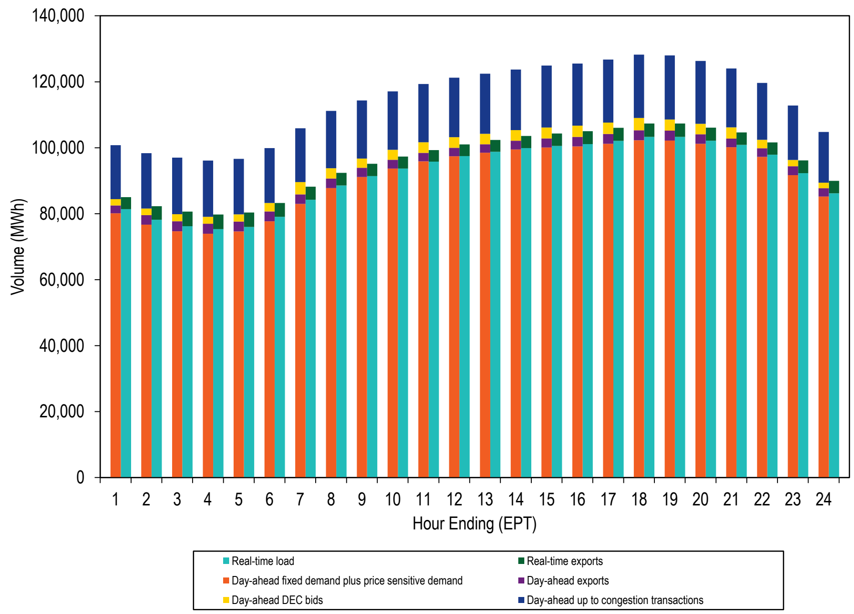
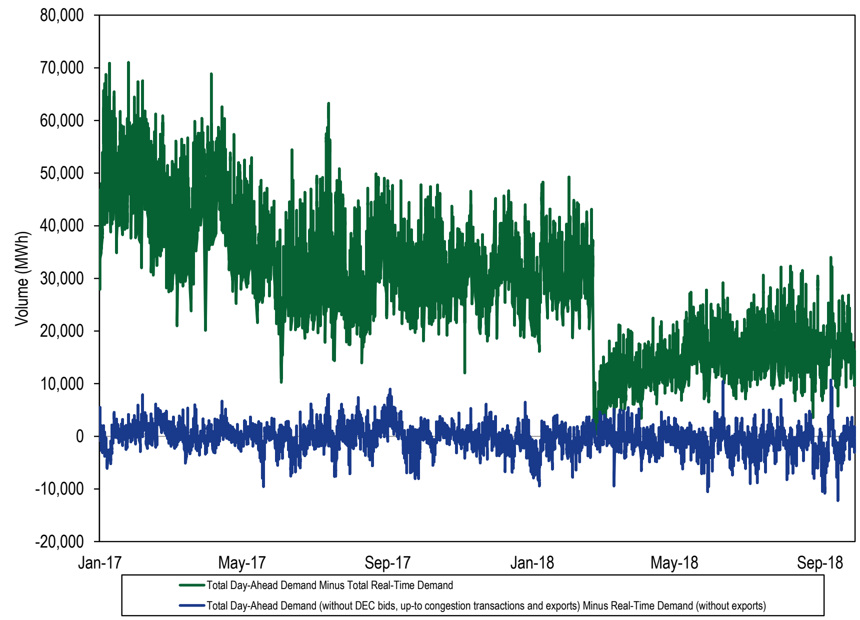


Figure 3-27 shows the difference between the day-ahead and real-time average daily demand for 2017 and the first nine months of 2018.

Figure 3-27 Difference between day-ahead and real-time demand (Average daily volumes): January 2017 through September 2018



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 3-23 shows the monthly average share of real-time load served by self-supply, bilateral contracts and spot purchase in the first nine months of 2017 and 2018 based on parent company. In the first nine months of 2018, 12.8 percent of real-time load was supplied by bilateral contracts, 29.7 percent by spot market purchase and 58.6 percent by self-supply. Compared with the first nine months of 2017, reliance on bilateral contracts decreased by 1.6 percentage points, reliance on spot supply increased by 2.2 percentage points and reliance on self-supply decreased by 0.2 percentage points.

Table 3-23 Sources of real-time supply: January through September, 2017 and 2018[53]

	2017			2018			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	15.6%	23.1%	61.3%	12.7%	29.0%	59.3%	(2.9%)	5.9%	(2.0%)
Feb	16.8%	22.9%	60.3%	13.5%	29.1%	58.5%	(3.3%)	6.2%	(1.9%)
Mar	14.0%	25.3%	60.7%	12.0%	31.8%	57.2%	(2.0%)	6.5%	(3.5%)
Apr	13.0%	26.9%	60.1%	13.1%	30.2%	57.7%	0.1%	3.3%	(2.4%)
May	13.3%	25.1%	62.3%	12.6%	29.8%	58.6%	(0.6%)	4.7%	(3.7%)
Jun	13.3%	28.0%	59.9%	12.6%	28.5%	60.0%	(0.6%)	0.5%	0.1%
Jul	15.0%	26.9%	59.5%	13.7%	28.3%	59.4%	(1.2%)	1.3%	(0.1%)
Aug	15.5%	26.3%	59.6%	11.8%	29.0%	60.6%	(3.7%)	2.7%	1.1%
Sep	14.0%	30.0%	57.2%	13.6%	30.1%	57.6%	(0.4%)	0.1%	0.4%
Jan-Sep	14.4%	27.5%	58.9%	12.8%	29.7%	58.6%	(1.6%)	2.2%	(0.2%)

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 3-24 shows the monthly average share of day-ahead demand served by self-supply, bilateral contracts and spot purchases in the first nine months of 2017 and 2018, based on parent companies. In the first nine months of 2018, 9.6 percent of day-ahead demand was supplied by bilateral contracts, 31.1 percent by spot market purchases and 59.3 percent by self-supply. Compared with the first nine months of 2017, reliance on bilateral contracts decreased by 2.0 percentage points, reliance on spot supply increased by 3.1 percentage points, and reliance on self-supply decreased by 1.1 percentage points.

53 Table 3-23 and Table 3-24 were calculated as of October 10, 2018. The values may change slightly as billing values are updated by PJM.

Table 3-24 Sources of day-ahead supply: January through September, 2017 and 2018

	2017			2018			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	13.5%	24.1%	62.4%	9.2%	31.9%	58.9%	(4.3%)	7.8%	(3.5%)
Feb	14.0%	25.3%	60.7%	10.2%	31.3%	58.5%	(3.9%)	6.0%	(2.2%)
Mar	11.4%	27.6%	61.0%	9.1%	32.8%	58.1%	(2.3%)	5.2%	(3.0%)
Apr	10.7%	28.7%	60.6%	9.9%	31.9%	58.2%	(0.8%)	3.2%	(2.3%)
May	10.2%	27.5%	62.3%	9.4%	31.5%	59.1%	(0.9%)	4.0%	(3.1%)
Jun	10.7%	29.3%	60.1%	9.4%	29.8%	60.8%	(1.2%)	0.5%	0.7%
Jul	11.4%	29.3%	59.3%	10.6%	29.3%	60.2%	(0.8%)	(0.0%)	0.8%
Aug	11.8%	28.9%	59.3%	8.6%	30.4%	61.0%	(3.2%)	1.5%	1.7%
Sep	11.0%	31.6%	57.4%	10.5%	31.4%	58.1%	(0.5%)	(0.2%)	0.7%
Jan-Sep	11.7%	28.0%	60.3%	9.6%	31.1%	59.3%	(2.0%)	3.1%	(1.1%)

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 allow market based offers 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 with market power have the ability to evade 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. This is consistent with the Day-Ahead Energy Market objective of clearing resources (including physical and virtual resources) to meet the total demand (including physical and virtual demand) at the lowest bid production cost for the system over the 24 hour period. 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.[54] Prior to the implementation of hourly offers, dispatch cost was calculated as:

$$\{(\text{Incremental Energy Offer@EcoMin} \times \text{EcoMin MW}) + \text{No Load Cost}\} \times \text{Min Run Time} + \text{Start Cost}$$

Beginning November 1, 2017, with hourly differentiated offers, the cheaper of cost and price based offers are determined using total dispatch cost, where:

$$\text{Total Dispatch Cost} = \text{Startup Cost} + \sum_{\text{Min Run}} \text{Hourly Dispatch Cost}$$

where the hourly dispatch cost is calculated for each hour using the offers applicable for that hour as:

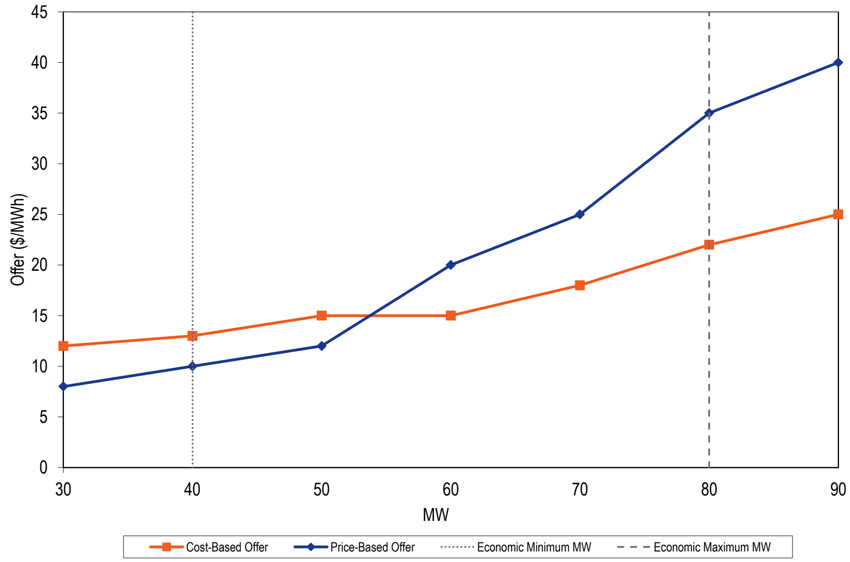
$$\text{Hourly Dispatch Cost} = (\text{Incremental Energy Offer@EcoMin} \times \text{EcoMin MW}) + \text{NoLoad Cost}$$

With the ability to submit offer curves with varying markups at different output levels in the price-based offer, unit owners with market power can

54 See PJM OA Schedule 1 § 6.4.1(g).

evade mitigation by using a low markup at low output levels and a high markup at higher output levels. Figure 3-28 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.

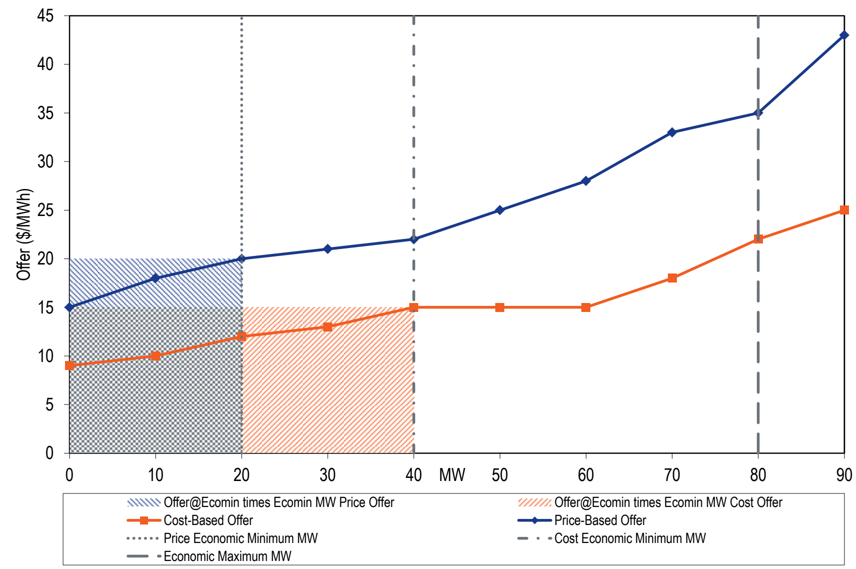
Figure 3-28 Offers with varying markups at different MW output levels



Offering a different economic minimum MW level, different minimum run times, or different start up and notification times in the cost-based and price-based offers can also be used to evade 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.

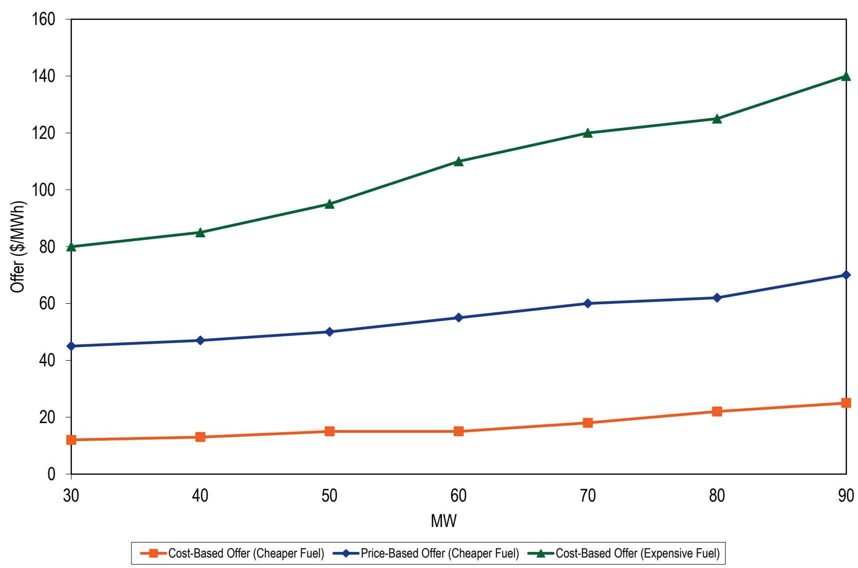
A unit may offer a lower economic minimum MW level on the price-based offer than the cost-based offer. Such a unit may appear to be cheaper to commit on the price-based offer even with a positive markup. A unit with a positive markup can have lower dispatch cost with the price-based offer with a lower economic minimum level compared to cost-based offer. Figure 3-29 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 3-29 Offers with a positive markup but different economic minimum MW



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 3-30 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 3-30 Dual fuel unit offers



These issues can be solved by simple rule changes.[55] 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 3-25. But offer capping remains a critical element of PJM market rules because it is designed to prevent the exercise of local market power. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation. The offer capping percentages shown in Table 3-25 include units that are committed to provide constraint relief whose owners failed the TPS test in the energy market excluding units that were committed for reliability reasons, providing black start and providing reactive support. Offer capped unit run hours and offer capped generation (in MWh) are shown as a percentage of the total run hours and the total generation (MWh) from all the units in the PJM energy market.[56] Beginning November 1, 2017, with the introduction of hourly offers, certain online units, whose owners fail the TPS test in the real time energy market for providing constraint relief, can be offer capped and dispatched on their cost based offer subsequent to a real time hourly offer update. This is reflected in the higher offer capping percentages in the real time energy market in the first nine months of 2018 compared to the first nine months of 2017.

Table 3-25 Offer capping statistics – energy only: January through September, 2014 to 2018

	Real-Time		Day-Ahead	
(Jan-Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2014	0.6%	0.3%	0.2%	0.1%
2015	0.4%	0.3%	0.2%	0.2%
2016	0.4%	0.3%	0.0%	0.1%
2017	0.3%	0.1%	0.0%	0.1%
2018	1.0%	0.5%	0.1%	0.1%

Table 3-26 shows the offer capping percentages including units committed to provide constraint relief and units committed for reliability reasons, including units committed to provide black start service and reactive support. 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

55 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.

56 In the previous versions of this report, these tables presented the offer cap percentages based on total bid unit hours and total load MWh. Beginning with this report, the statistics have been updated with percentages based on run hours and total generation MWh from units modeled in the energy market.

loop interfaces to, in some cases, model reactive constraints. The result was higher LMPs in the closed loops, 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 3-25.

Table 3-26 Offer capping statistics for energy and reliability: January through September, 2014 to 2018

	Real-Time		Day-Ahead	
(Jan-Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2014	0.9%	0.6%	0.5%	0.4%
2015	0.8%	0.9%	0.7%	0.8%
2016	0.4%	0.3%	0.1%	0.1%
2017	0.4%	0.4%	0.1%	0.3%
2018	1.2%	0.8%	0.2%	0.3%

Table 3-27 shows the offer capping percentages for units committed for reliability reasons, including units committed to provide black start service and reactive support. The data in Table 3-27 is the difference between the offer cap percentages shown in Table 3-26 and Table 3-25.

Table 3-27 Offer capping statistics for reliability: January through September, 2014 to 2018

	Real-Time		Day-Ahead	
(Jan-Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2014	0.3%	0.3%	0.3%	0.3%
2015	0.4%	0.6%	0.5%	0.6%
2016	0.0%	0.0%	0.1%	0.0%
2017	0.1%	0.3%	0.1%	0.2%
2018	0.1%	0.3%	0.1%	0.2%

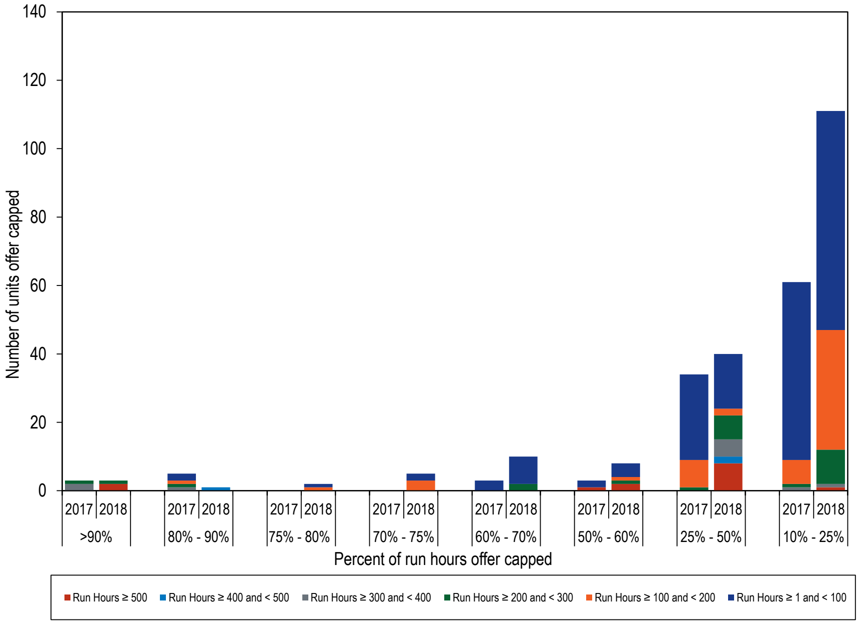
Table 3-28 presents data on the frequency with which units were offer capped in the first nine months of 2017 and 2018 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market and for reliability reasons. Table 3-28 shows that three units were offer capped for 90 percent or more of their run hours in the first nine months of 2018 and the first nine months of 2017.

Table 3-28 Real-time offer capped unit statistics: January through September, 2017 and 2018

		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
	2017	0	0	2	1	0	0
90%	2018	2	0	0	1	0	0
	2017	0	0	1	1	1	2
80% and < 90%	2018	0	1	0	0	0	0
	2017	0	0	0	0	0	0
75% and < 80%	2018	0	0	0	0	1	1
	2017	0	0	0	0	0	0
70% and < 75%	2018	0	0	0	0	3	2
	2017	0	0	0	0	0	3
60% and < 70%	2018	0	0	0	2	0	8
	2017	1	0	0	0	0	2
50% and < 60%	2018	2	0	0	1	1	4
	2017	0	0	0	1	8	25
25% and < 50%	2018	8	2	5	7	2	16
	2017	0	0	1	1	7	52
10% and < 25%	2018	1	0	1	10	35	64

Figure 3-31 shows the frequency with which units were offer capped in the first nine months of 2017 and 2018 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market and for reliability reasons.

Figure 3-31 Real-time offer capped unit statistics: January through September, 2017 and 2018



TPS Test Statistics

In the first nine months of 2018, the AECO, AEP, APS, ATSI, BGE, ComEd, DEOK, Dominion, DPL, EKPC, Met-Ed, PECO, PENELEC, and PSEG control zones experienced congestion resulting from one or more constraints binding for 75 or more hours or resulting from an interface constraint (Table 3-29). The DAY, DLCO, JCPL, Pepco, PPL and RECO control zones did not have constraints binding for 75 or more hours in the first nine months of 2018. Table 3-29 shows that AEP, BGE, ComEd, Dominion and PSEG 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 every year from the first nine months of 2009 through 2018. The constrained hours in the AEP Zone increased from 469 hours in the first nine months of 2017 to 1,592 hours in the first nine months of 2018 as a result of increased constraint hours for Tanners Creek - Miami Fort, Capitol Hill – Chemical, and Cloverdale due to cold weather related demand in January 2018. The constrained hours in the Met-Ed Zone increased from less than 75 hours in the first nine months of 2017 to 1,259 hours in the first nine months of 2018 as a result of outages at the Hunterstown station. The constrained hours in the PECO Zone decreased from 975 hours in the first nine months of 2017 to 218 hours in the first nine months of 2018 due to completion of outages at the Emilie substation.

Table 3-29 Congestion hours resulting from one or more constraints binding for 75 or more hours or from an interface constraint: January through September, 2009 through 2018

	(Jan - Sep)									
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
AECO	149	163	234	0	0	0	192	413	0	94
AEP	1,005	1,265	2,452	178	2,018	1,821	1,891	633	469	1,592
APS	421	1,121	87	89	0	170	451	157	136	184
ATSI	140	0	0	208	68	481	424	1	427	2,355
BGE	127	274	368	1,582	1,192	4,416	6,006	8,506	1,748	2,644
ComEd	784	2,108	1,118	1,808	3,169	1,928	1,708	4,754	1,401	761
DEOK	0	0	0	185	0	0	0	0	0	75
DLCO	156	393	0	209	0	223	617	0	0	0
Dominion	456	889	1,266	559	674	77	1,341	647	80	136
DPL	0	111	0	382	783	542	1,138	2,691	326	398
EKPC	0	0	0	0	0	0	0	0	0	368
JCPL	0	0	0	0	0	0	79	0	94	0
Met-Ed	0	168	0	0	0	0	222	0	0	1,259
PECO	247	0	276	0	390	1,826	718	826	975	218
PENELEC	80	96	77	0	0	2,147	1,287	451	1,992	1,338
Pepco	149	0	76	143	200	41	0	0	0	0
PPL	176	117	40	146	609	148	224	398	1,370	0
PSEG	379	515	1,132	259	1,993	2,268	2,509	170	159	324

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 2018.[57] 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. Until November 1, 2017, only uncommitted resources, started to relieve the transmission

57 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>.

constraint, were subject to offer capping. Beginning November 1, 2017, under certain circumstances, online resources that are committed beyond their original commitment (day-ahead or real-time) can be offer capped if the owner fails the TPS test, and the latest available cost-based offer is determined to be cheaper than the price-based offer.[58] Units running in real time as part of their original commitment on the price-based offer on economics, that can provide incremental relief to a constraint, cannot be switched to their cost-based offer. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

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

Table 3-30 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 3-30 Three pivotal supplier test details for interface constraints: January through September, 2018

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	398	326	10	0	10
	Off Peak	631	465	11	0	11
AEP - DOM	Peak	466	343	9	0	9
	Off Peak	632	541	12	0	12
AP South	Peak	299	562	15	3	12
	Off Peak	272	509	16	5	10
Bedington - Black Oak	Peak	184	125	9	0	9
	Off Peak	201	130	10	0	10
CPL - DOM	Peak	225	314	8	1	8
	Off Peak	142	254	7	0	7
East	Peak	NA	NA	NA	NA	NA
	Off Peak	293	223	6	0	6
West	Peak	269	191	9	0	9
	Off Peak	300	362	12	0	12

The three pivotal supplier test is applied every time the PJM market system solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for capping. 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. Offline units that are committed to provide relief for a transmission constraint, whose owners fail the TPS test, are committed on the cheaper of their cost or price-based offers. Beginning November 1, 2017, with the introduction of hourly offers and intraday offer updates, certain online units whose commitment is extended beyond the day-ahead or real-time commitment, whose owners fail the TPS test, are also switched to the cost-based offer if it is cheaper than the price-based offer. Table 3-31 provides, for the identified interface constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. 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 other than relief to a binding constraint.

58 See PJM, OATT Attachment K Appendix § 6.4.1 (Offer Price Caps - Applicability) (January 3, 2018).

Table 3-31 Summary of three pivotal supplier tests applied for interface constraints: January through September, 2018

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
5004/5005 Interface	Peak	829	829	100%	14	2%	2%
	Off Peak	844	836	99%	22	3%	3%
AEP - DOM	Peak	2,182	2,172	100%	38	2%	2%
	Off Peak	3,342	3,341	100%	97	3%	3%
AP South	Peak	165	163	99%	3	2%	2%
	Off Peak	129	128	99%	10	8%	8%
Bedington - Black Oak	Peak	516	508	98%	0	0%	0%
	Off Peak	670	664	99%	12	2%	2%
CPL - DOM	Peak	1,535	1,504	98%	14	1%	1%
	Off Peak	1,120	1,119	100%	2	0%	0%
East	Peak	NA	NA	NA	NA	NA	NA
	Off Peak	38	29	76%	0	0%	0%
West	Peak	63	63	100%	0	0%	0%
	Off Peak	185	179	97%	0	0%	0%

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.[59] 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 2018, 2017, 2016, 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 include minimum run time (MRT) and turn down ratio (TDR, the ratio of economic maximum MW to economic 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

59 See PJM OASchedule 1 § 6.6 (Minimum Generator Operating Parameters—Parameter-Limited Schedules).

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 2017 and prior periods, even though other parameters were subject to parameter limits. 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.

The PJM process for the review of unit specific parameter limit adjustments is generally described in Manual 11: Energy and Ancillary Services Market Operations. The standards used by PJM to review the requests are currently not described in the tariff or PJM manuals. The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources.

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 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.

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.[60] The Commission directed that capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.[61] The Commission directed PJM to submit tariff language to establish a process through which

60 151 FERC ¶ 61,208 at P 437 (2015) (June 9th Order).
61 *Id* at P 439.

capacity performance resources that operate outside the defined unit-specific parameter limits can justify such operation and therefore remain eligible for make whole payments.[62]

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 reference resource used for the Cost of New Entry (CONE) calculation 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.

62 *Id* at P 440.

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.[63] 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 Index

Table 3-32 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using unadjusted cost-based offers. Table 3-33 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using adjusted cost-based offers. The unadjusted markup is the difference between the price-based offer and the cost-based offer including the 10 percent adder in the cost-based offer. The adjusted markup is the difference between the price-based offer and the cost-based offer excluding the 10 percent adder from the cost-based 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.[64] 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-based offer. The 10 percent adder was included 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 many gas fired and oil fired units have also begun to exclude the 10 percent adder. The introduction of hourly offers and intraday offer updates in November 2017 allows gas and oil generators to directly incorporate the impact of ambient temperature changes in fuel consumption in offers.

The unadjusted markup is calculated as the difference between the price-based offer and the cost-based offer including the additional 10 percent in the cost-based offer for coal, gas and oil fired units. The adjusted markup is calculated as the difference between the price-based offer and the cost-based offer excluding the additional 10 percent from the cost-based 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 components of operating and maintenance costs

63 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.

64 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.

that are not short run marginal costs. While the 10 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.[65]

In the first nine months of 2018, 89.8 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 negative (-$0.46 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $25 and $50 was positive ($2.24 per MWh) when using unadjusted cost-based offers. 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 2018, less than 0.1 percent had offer prices above $400 per MWh. Among the units that were marginal in the first nine months of 2017, none had offer prices greater than $400 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the first nine months of 2018 was more than $500, while the highest markup in the first nine months of 2017 was more than $700.

Table 3-32 Average, real-time marginal unit markup index (By offer price category unadjusted): January through September, 2017 and 2018

	2017 (Jan - Sep)			2018 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.17	$0.21	65.2%	0.03	($0.46)	55.2%
$25 to $50	0.06	$1.67	27.8%	0.07	$2.24	34.6%
$50 to $75	0.38	$22.34	1.8%	0.35	$19.91	3.2%
$75 to $100	0.28	$24.16	0.7%	0.33	$27.13	1.1%
$100 to $125	0.38	$40.95	0.2%	0.31	$33.99	0.6%
$125 to $150	0.25	$32.45	0.3%	0.11	$15.28	1.2%
>= $150	0.01	$1.38	4.0%	0.08	$18.90	4.0%

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

Table 3-33 Average, real-time marginal unit markup index (By offer price category adjusted): January through September, 2017 and 2018

	2017 (Jan - Sep)			2018 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.25	$1.75	65.2%	0.11	$1.22	55.2%
$25 to $50	0.15	$4.34	27.8%	0.15	$4.91	34.6%
$50 to $75	0.44	$25.43	1.8%	0.41	$23.26	3.2%
$75 to $100	0.35	$30.01	0.7%	0.39	$32.34	1.1%
$100 to $125	0.43	$47.34	0.2%	0.38	$40.98	0.6%
$125 to $150	0.32	$41.91	0.3%	0.20	$26.18	1.2%
>= $150	0.10	$20.25	4.0%	0.17	$36.82	4.0%

Table 3-34 shows the percentage of marginal units that had markups, calculated using unadjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types.[66] Table 3-35 shows the percentage of marginal units that had markups, calculated using adjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types. In the first nine months of 2018, using unadjusted cost-based offers for coal units, 49.93 percent of marginal coal units had negative markups. In the first nine months of 2018, using adjusted cost-based offers for coal units, 17.88 percent of marginal coal units had negative markups.

Table 3-34 Percent of marginal units with markup below, above and equal to zero (By fuel type unadjusted): January through September, 2017 and 2018

	2017 (Jan - Sep)			2018 (Jan - Sep)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	45.78%	21.65%	32.57%	49.94%	21.31%	28.75%
Gas	37.18%	13.22%	49.60%	43.74%	10.74%	45.53%
Oil	38.88%	60.20%	0.92%	9.28%	82.24%	8.48%

Table 3-35 Percent of marginal units with markup below, above and equal to zero (By fuel type adjusted): January through September, 2017 and 2018

	2017 (Jan - Sep)			2018 (Jan - Sep)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	24.76%	5.47%	69.77%	17.89%	0.07%	82.04%
Gas	9.72%	5.88%	84.40%	9.37%	0.06%	90.57%
Oil	0.07%	0.00%	99.93%	0.58%	0.00%	99.42%

66 Other fuel types were excluded based on data confidentiality rules.

Figure 3-32 shows the frequency distribution of hourly markups for all gas units offered in the first nine months of 2017 and the first nine months of 2018 using unadjusted cost-based offers. The highest markup within the economic operating range of the unit's offer curve was used for creating the frequency distributions.[67] Of the gas units offered in the PJM market in the first nine months of 2018, nearly 28.5 percent of gas unit-hours had a maximum markup that was negative. More than 10.8 percent of gas fired unit-hours had a maximum markup above $100 per MWh.

Figure 3-32 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: January through September, 2017 and 2018

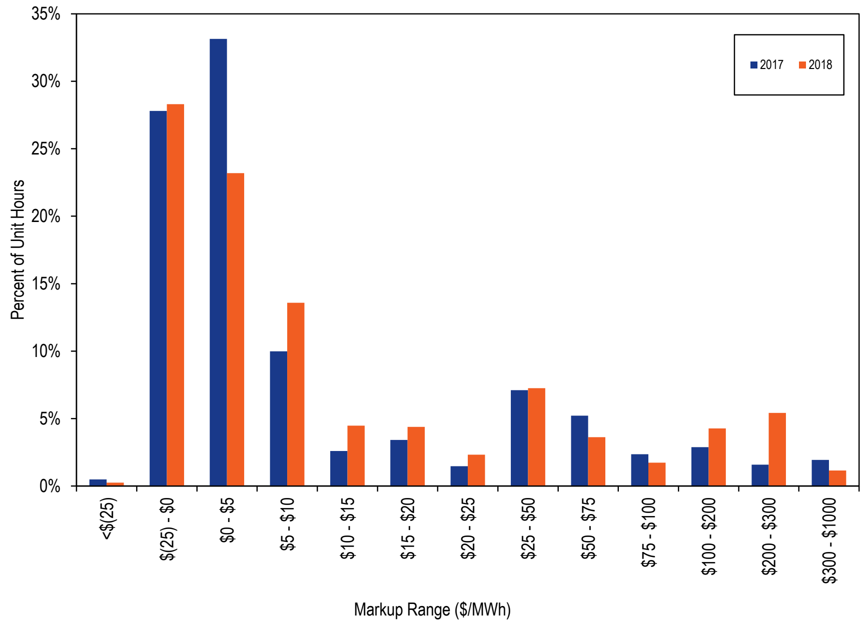


Figure 3-33 shows the frequency distribution of hourly markups for all coal units offered in the first nine months of 2017 and 2018 using unadjusted cost-based offers. Of the coal units offered in the PJM market in the first nine months of 2018, nearly 38 percent of coal unit-hours had a maximum markup that was negative or equal to zero.

Figure 3-33 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: January through September, 2017 and 2018

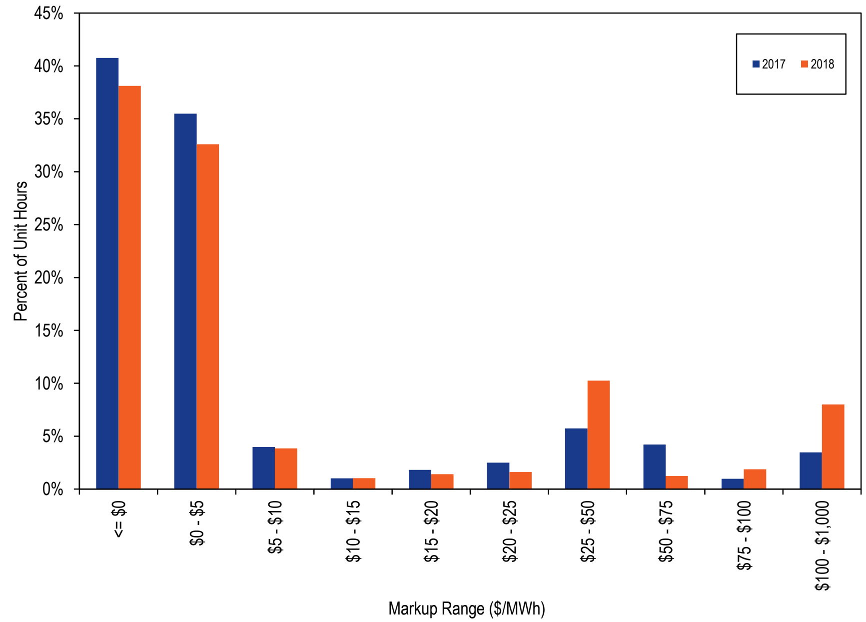
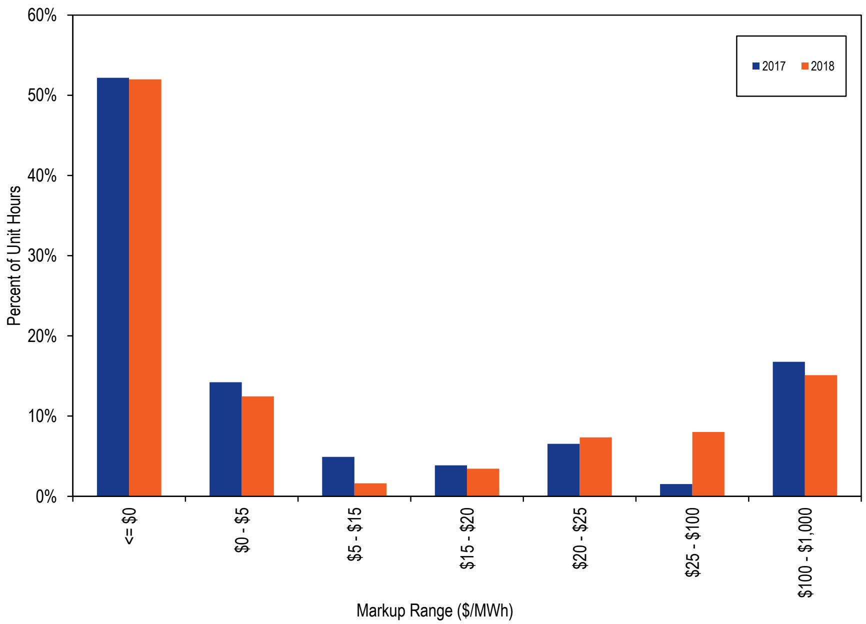


Figure 3-34 shows the frequency distribution of hourly markups for all offered oil units in the first nine months of 2017 and 2018 using unadjusted cost-based offers. Of the oil units offered in the PJM market in the first nine months of 2018, nearly 51 percent of oil unit-hours had a maximum markup that was negative or equal to zero. More than 15 percent of oil fired unit-hours had a maximum markup above $100 per MWh.

67 The categories in the frequency distribution were chosen so as to maintain data confidentiality.

Figure 3-34 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: January through September, 2017 and 2018

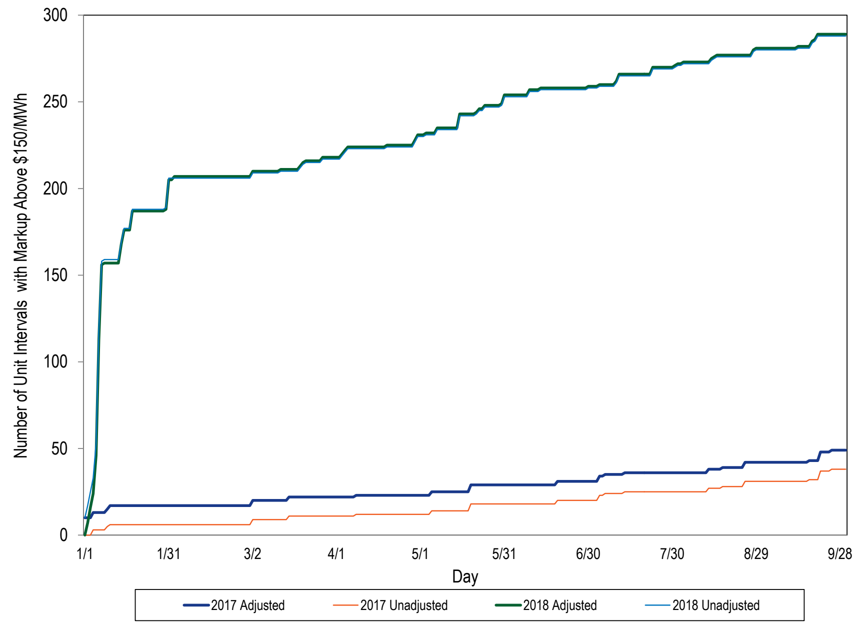


The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion 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 3-35 shows the number of marginal unit intervals in the first nine months of 2018 and 2017 with markup above $150 per MWh. The number of intervals with markups above $150 per MWh increased during the first eight days of January 2018, when the PJM region experienced low temperatures.

Figure 3-35 Cumulative number of unit intervals with markups above $150 per MWh: January through September, 2017 and 2018



Day-Ahead Markup Index

Table 3-36 shows the average markup index of marginal generating units in the Day-Ahead Energy Market, by offer price category using unadjusted cost-based offers. The majority of marginal units are virtual transactions, which do not have markup. In the first nine months of 2018, 95.2 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 negative (-$0.66 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $25 and $50 was positive ($1.88 per MWh) when using unadjusted cost-based offers.

Some marginal units did have substantial markups. Among the units that were marginal in the day-ahead market in the first nine months of 2017 and 2018, none had offer prices above $400 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the day-ahead market in the first nine months of 2018 was about $200 per MWh while the highest markup in the first nine months of 2017 was about $50 per MWh.

Table 3-36 Average day-ahead marginal unit markup index (By offer price category, unadjusted): January through September, 2017 and 2018

	2017 (Jan - Sep)			2018 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.17	$0.23	61.5%	0.03	($0.66)	54.9%
$25 to $50	0.10	$3.23	32.8%	0.08	$1.88	40.4%
$50 to $75	0.21	$11.82	0.7%	0.27	$15.15	2.1%
$75 to $100	0.02	$1.43	0.4%	0.27	$20.67	0.7%
$100 to $125	0.00	$0.00	0.0%	0.01	$0.02	0.4%
$125 to $150	0.00	$0.00	0.0%	0.07	$8.72	0.6%
>= $150	(0.01)	($1.56)	4.6%	0.08	$15.84	1.0%

Table 3-37 shows the average markup index of marginal generating units in the Day-Ahead Energy Market, by offer price category using adjusted cost-based offers. In the first nine months of 2018, 0.7 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 decreased from 0.25 in the first nine months of 2017, to 0.11 in the first nine months of 2018 in the offer price category less than $25.

Table 3-37 Average day-ahead marginal unit markup index (By offer price category, adjusted): January through September, 2017 and 2018

	2017 (Jan - Sep)			2018 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.25	$1.90	61.5%	0.11	$1.12	54.9%
$25 to $50	0.18	$5.68	32.8%	0.16	$4.58	40.4%
$50 to $75	0.28	$15.65	0.7%	0.34	$18.87	2.1%
$75 to $100	0.11	$9.80	0.4%	0.33	$26.38	0.7%
$100 to $125	0.00	$0.00	0.0%	0.10	$10.13	0.4%
$125 to $150	0.09	$11.86	0.0%	0.15	$19.73	0.6%
>= $150	0.09	$16.75	4.6%	0.16	$33.10	1.0%

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. Cost of inputs consumed or converted to produce energy, and the costs associated with byproducts that result from consuming or converting materials to produce energy, net of any revenues from the sale of those byproducts. The categories of short run marginal costs are:

- Fuel costs: Includes commodity costs, delivery costs (such as variable transportation costs), fuel supplier fees and taxes;
- Emission allowance costs: Includes costs of emission allowances and any variable regulatory fees;
- Operating costs: Includes water purchases, water or waste water treatment control reagents, emission control reagents, equipment lubricants, electricity byproducts disposal;
- Energy market opportunity costs;[68]

- 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

Fuel cost policies document the process by which Market Sellers calculate the fuel cost component of their cost-based offers. Short run marginal fuel costs include commodity costs, transportation costs, fees, and taxes for the purchase of fuel.

Fuel Cost Policy Review

The standards for the MMU's market power evaluation are that FCPs be algorithmic, verifiable and systematic, accurately reflecting the short run marginal cost of producing energy. In its filings with FERC, PJM agreed with the MMU that FCPs should be verifiable and systematic:[69]

- Verifiable: Must provide a fuel price that can be calculated by the MMU after the fact with the same data available to the Market Seller at the time the decision was made and documentation for that data from a public or a private source.
- Systematic: Document a standardized method or methods for calculating fuel costs including objective triggers for each method.[70]

PJM and FERC did not agree that Fuel Cost Policies should be algorithmic:[71]

- Algorithmic: Must use a set of defined, logical steps. These steps may be as simple as a single number from a contract, a simple average of broker quotes, a simple average of bilateral offers, or the weighted average index price posted on the Intercontinental Exchange trading platform ('ICE').[72]

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

The MMU recommends that the tariff be changed to allow units to have Fuel Cost Policies that do not include fuel procurement practices, including fuel contracts. Fuel procurement practices, including fuel contracts, may be used as the basis for Fuel Cost Policies but should not be required. In a large number of approved Fuel Cost Policies, the actual fuel procurement process plays no role in calculating the Market Seller's accurate estimate of the daily replacement value of their fuel.

The MMU recommends that PJM change the Fuel Cost Policy requirement to apply only to units that will be offered with non zero cost-based offers. PJM should set to zero the cost-based offers of units without an approved Fuel Cost Policy.

Hourly Offers and Intraday Offer Updates

On November 1, 2017, PJM implemented hourly offers and intraday offer updates. Hourly offers means the ability to offer hourly differentiated offers (up to one offer per hour instead of one offer per day). Intraday offer updates

68 See PJM Operating Agreement Schedule 2 (a)
69 Answer of PJM Interconnection, L.L.C. to Protests and Comments, Docket No. ER16-372-002 (October 7, 2016) ("October 7th Filing") at P 11.
70 Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) ("September 16th Filing") at P 8.
71 October 7th Filing at P12. 158 FERC ¶ 61,133 at P 57 (2017) ("February 3rd Order").
72 September 16th Filing at P 8.

means the ability to make changes to an offer after the rebid period. All participants are eligible to make hourly offers. Participants must opt in on a monthly basis to make intraday offer updates. Table 3-38 shows the daily average number of units that opted in to intraday offer updates and as a reference the daily average number of units that make positive offers. In September 2018, a daily average of 330 natural gas fired units had opted in for intraday offer updates out of a daily average of 445 natural gas fired units. This is an increase of 24.2 percent from the daily average number of natural gas fired units that opted in to intraday offer updates in December 2017.

Table 3-38 Average number of units opted in for intraday offers by month: 2017 and 2018

	2017						2018					
	Number of units opt in			Number of units with positive offers			Number of units opt in			Number of units with positive offers		
	Natural Gas	Other Fuels	Total	Natural Gas	Other Fuels	Total	Natural Gas	Other Fuels	Total	Natural Gas	Other Fuels	Total
Jan	0.0	0.0	0.0	444.2	419.7	**863.9**	291.0	33.0	324.0	444.0	394.7	838.7
Feb	0.0	0.0	0.0	445.2	419.0	**864.2**	302.0	33.0	335.0	444.0	395.7	839.7
Mar	0.0	0.0	0.0	447.5	418.4	**865.9**	304.0	33.0	337.0	444.5	394.6	839.0
Apr	0.0	0.0	0.0	448.4	419.9	**868.3**	312.6	33.0	345.6	445.9	394.0	839.9
May	0.0	0.0	0.0	449.7	417.1	**866.7**	327.5	33.0	360.5	444.9	393.2	838.0
Jun	0.0	0.0	0.0	451.7	417.5	**869.2**	330.0	33.0	363.0	443.3	369.8	813.1
Jul	0.0	0.0	0.0	449.0	410.4	**859.4**	330.0	35.0	365.0	443.0	367.4	810.5
Aug	0.0	0.0	0.0	449.0	401.5	**850.5**	330.0	36.0	366.0	445.0	363.7	808.7
Sep	0.0	0.0	0.0	448.5	401.4	**849.9**	330.0	36.0	366.0	445.2	360.1	805.3
Oct	0.0	0.0	0.0	450.8	399.5	**850.3**						
Nov	243.6	29.0	272.6	442.3	396.8	**839.1**						
Dec	265.8	29.0	294.8	444.2	395.2	**839.4**						

Table 3-39 shows the average number of units that made hourly differentiated offers in the day-ahead market or rebid period.[73] In September 2018, an average of 253 units made hourly differentiated offers. This is an increase of 17.7 percent from the average number of units that made hourly differentiated offers in December 2017.

Table 3-39 Average number of units with hourly differentiated offers by month: 2017 and 2018

	2017			2018		
	Natural Gas	Other Fuels	Total	Natural Gas	Other Fuels	Total
Jan	0.0	0.0	0.0	207.0	12.4	219.4
Feb	0.0	0.0	0.0	214.4	10.5	224.9
Mar	0.0	0.0	0.0	215.0	11.6	226.6
Apr	0.0	0.0	0.0	231.3	11.4	242.8
May	0.0	0.0	0.0	242.6	11.8	254.4
Jun	0.0	0.0	0.0	246.6	9.0	255.6
Jul	0.0	0.0	0.0	247.0	11.3	258.3
Aug	0.0	0.0	0.0	259.6	16.6	276.2
Sep	0.0	0.0	0.0	238.2	14.9	253.1
Oct	0.0	0.0	0.0			
Nov	212.8	10.7	223.5			
Dec	200.7	14.4	215.1			

Table 3-40 shows the average number of units that made rebid offer updates and intraday offer updates. In September 2018, an average of 128.6 units made intraday offer updates. This is an increase of 25.2 percent from the average number of units that made intraday offer updates in December 2017. Prior to November 2017, real-time offer updates refers to offer updates made during the rebid period.

73 The information in this table was not correct for the 2017 State of the Market Report for PJM, the 2018 Quarterly State of the Market Report for PJM: January through March and the 2018 Quarterly State of the Market Report for PJM: January through June.

Table 3-40 Average number of units making rebid or intraday offer updates by month: 2017 and 2018

	2017			2018		
	Average number of units that made real-time offer updates			Average number of units that made real-time offer updates		
	Natural Gas	Other Fuels	Total	Natural Gas	Other Fuels	Total
Jan	30.4	4.3	34.6	114.1	3.8	117.8
Feb	33.0	5.0	38.0	117.3	4.9	122.2
Mar	28.9	4.6	33.5	113.5	6.2	119.7
Apr	28.1	5.1	33.2	116.8	5.2	122.0
May	31.6	4.6	36.2	122.2	4.8	127.0
Jun	28.0	4.9	32.9	124.7	4.4	129.1
Jul	22.0	3.9	25.9	128.1	4.4	132.5
Aug	30.7	1.8	32.5	130.2	3.4	133.6
Sep	31.5	1.1	32.5	124.3	4.3	128.6
Oct	31.4	1.5	32.8			
Nov	99.9	4.7	104.6			
Dec	99.0	3.7	102.7			

Cost-Based Offer Penalties

In addition to implementing the Fuel Cost Policy approval process, the February 3, 2017, FERC Order created a process for penalizing generators identified by PJM or the MMU with cost-based offers that do not comply with Schedule 2 of the PJM Operating Agreement and PJM Manual 15.[74] Penalties became effective May 15, 2017.

In the first nine months of 2018, 191 penalty cases were identified, 99 resulted in assessed cost-based offer penalties, 22 resulted in disagreement between the MMU and PJM, and 66 remain pending PJM's determination. These cases were from 137 units owned by 33 different companies. Table 3-42 shows the penalties by the year in which participants were notified.

Table 3-41 Cost-based offer penalty cases by year notified: 2017 through September 2018

Year notified	Cases	Assessed penalties	MMU and PJM Disagreement	Pending cases	Number of units impacted	Number of companies impacted
2017	57	56	1	0	55	16
2018	191	99	22	66	137	33
Total	248	155	23	66	187	40

74 158 FERC ¶ 61,133 (2017) ("February 3rd Order").

Since 2017, 248 penalty cases have been identified, 155 resulted in assessed cost-based offer penalties, 23 resulted in disagreement between the MMU and PJM, and 66 remain pending PJM's determination. The 155 cases were from 157 units owned by 31 different companies. The total penalties were $1.3 million, charged to units that totaled 30,456 available MW. The average penalty was $2.06 per available MW.[75] Table 3-42 shows the total cost-based offer penalties since 2017 by year.

Table 3-42 Cost-based offer penalties by year: May 2017 through September 2018

Year	Number of units	Number of companies	Penalties	Average Available Capacity Charged (MW)	Average Penalty ($/MW)
2017	92	19	$556,826	16,930	$1.56
2018	65	15	$744,573	13,526	$2.71
Total	157	31	$1,301,399	30,456	$2.06

The incorrect cost-based offers resulted from incorrect application of Fuel Cost Policies, lack of approved Fuel Cost Policies, Fuel Cost Policy violations, miscalculation of no load costs, inclusion of prohibited maintenance costs, use of incorrect incremental heat rates, use of incorrect start cost, and use of incorrect emission costs.

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 PJM Manual 15 be replaced with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers.

VOM Costs

PJM Manual 15 and the PJM Operating Agreement Schedule 2 include rules related to VOM costs. These rules are unclear. PJM Manual 15 provides for the inclusion of Variable Operating and Maintenance (VOM) costs in energy market cost-based offers. PJM Manual 15 is unclear regarding the inclusion of

75 Cost-based offer penalties are assessed by hour. Therefore, a $1 per available MW penalty results in a total of $24 for a 1 MW unit if the violation is for the entire day.

variable operating costs. PJM Manual 15 includes provisions for incremental maintenance costs mainly based on FERC's accounting system. A competitive offer, at short run marginal costs, includes only operating costs. Effective market power mitigation requires excluding maintenance costs from cost-based offers.

High VOM levels allow generators to economically withhold energy and to exercise market power even when offers are set to cost to mitigate market power. The MMU recommendation to limit cost-based offers to short run marginal costs would prevent such withholding. When units are not committed due to high VOM costs and instead a unit with higher short run marginal costs is committed, the market outcome is inefficient. When units that fail the TPS test are committed on their price-based offer when their short run marginal cost is lower, the market outcome is inefficient.

FERC System of Accounts

PJM Manual 15 relies 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 PJM Manual 15.

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 incremental offer 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. PJM Manual 15 allows for a peaking cyclic factor of three, which means that a unit with a $300 per hour (EOH) VOM cost can add $180 per MWh to a 5 MW peak segment.[76]

The MMU recommends the removal of all cyclic starting and peaking factors from PJM Manual 15.

76 The peak adder is equal to $300 times three divided by 5 MW.

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 not short run marginal costs.

The MMU recommends the removal of all labor costs from the PJM Manual 15.

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. To account for this, PJM Manual 15 requires reducing the station service MWh used during the start sequence by the output in MWh produced by each combustion turbine after synchronization and before the HRSG steam pressure matches the steam turbine steam pressure. The formula and the language in this definition are not appropriate and are unclear.

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. Exceptions to this definition should be granted when the amount of fuel used from synchronization to when the unit becomes dispatchable is greater than the no load heat plus the output during this period times the incremental heat rate.

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 PJM Manual 15.

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.[77] 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. Units have the opportunity to recover ACR in the capacity market.

For those reasons, the MMU recommended the elimination of FMU and AU adders.[78] FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

The rules governing FMU and AU adders significantly changed on November 1, 2014.[79]

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.

77 110 FERC ¶ 61,053 (2005).
78 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>.
79 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 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, with the conditions addressed.

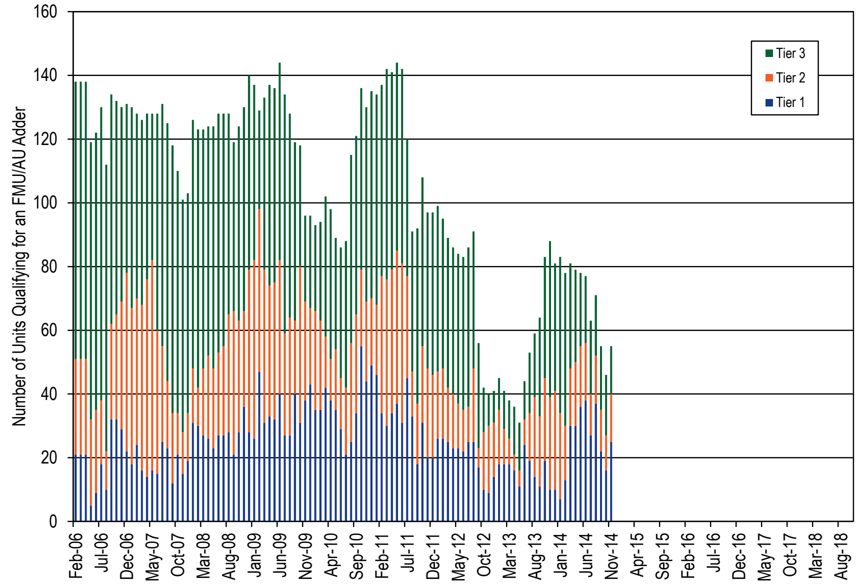
In addition to being offer capped for the designated percent of run hours, in order to qualify for an FMU adder, a generating unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis, divided by the unit's MW of installed capacity (in $/MW-year) must 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.[80]

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.[81] 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.

Effective in planning year 2020/2021, default Avoidable Cost Rates will no longer be defined. If a generating unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis (in $/MW-year) are greater than zero, and if the generating unit does not have an approved unit specific Avoidable Cost Rate, the generating unit will not qualify as an FMU as the Avoidable Cost Rate will be assumed to be zero for FMU qualification purposes.

Figure 3-36 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.[82] 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.

Figure 3-36 Frequently mitigated units and associated units (By month): February 2006 through September 2018



80 OA, Schedule 1 § 6.4.2.
81 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.
82 OA, Schedule 1 § 6.4.2. In 2007, the FERC approved OA revisions to clarify the AU criteria.

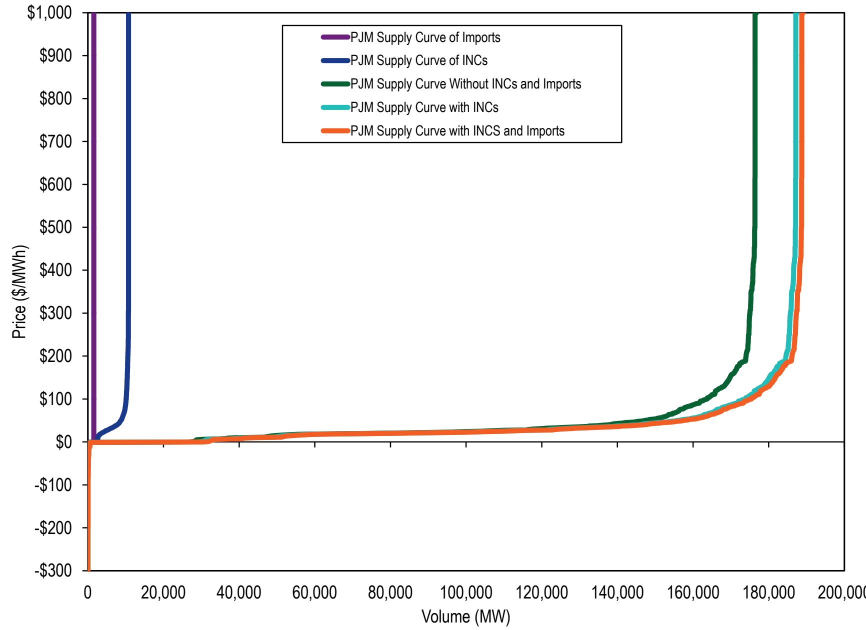
Virtual Offers and Bids

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. On February 20, 2018, FERC issued an Order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces.[83] Up to congestion transactions may be submitted between any two buses on a list of 49 buses, eligible for up to congestion transaction bidding.[84] 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 3-37 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 3-37 Day-ahead aggregate supply curves: 2017 example day



83 162 FERC ¶ 61,139 (2018).

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

Figure 3-38 shows example PJM day-ahead aggregate supply curves for the typical dispatch price range.

Figure 3-38 Typical dispatch price range for day-ahead aggregate supply curves: 2017 example day

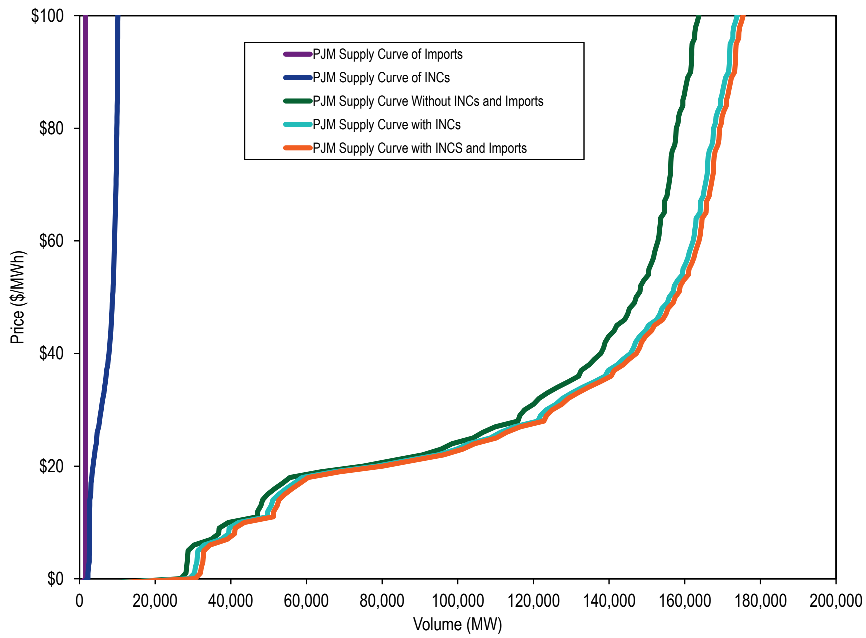


Table 3-43 shows the hourly average number of cleared and submitted increment offers and decrement bids by month in January 2017 through September 2018. The hourly average submitted and cleared increment MW decreased by 32.3 percent and 47.0 percent, from 8,490 MW and 4,858 MW in the first nine months of 2017 to 5,746 MW and 2,577 MW in the first nine months of 2018. The hourly average submitted and cleared decrement MW decreased by 17.3 percent and 34.9 percent, from 8,318 MW and 4,380 MW in the first nine months of 2017 to 6,879 MW and 2,851 MW in the first nine months of 2018.

Table 3-43 Average hourly number of cleared and submitted INCs and DECs by month: January 2017 through September 2018

		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
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	Oct	3,927	6,498	309	1,128	3,111	6,008	168	586
2017	Nov	3,558	6,454	290	1,240	2,632	5,970	179	683
2017	Dec	3,404	6,029	234	1,102	3,138	7,400	177	793
2017	Annual	4,562	7,968	256	1,220	4,035	7,874	164	753
2018	Jan	2,903	6,834	293	1,387	2,728	8,782	196	1,188
2018	Feb	2,519	5,415	280	1,160	2,418	5,857	136	634
2018	Mar	2,790	5,985	521	1,266	2,580	7,020	330	978
2018	Apr	3,060	5,848	222	792	2,555	6,919	197	801
2018	May	2,892	5,563	168	650	3,158	6,684	154	662
2018	Jun	2,444	5,601	142	662	3,041	6,460	147	609
2018	Jul	1,829	4,984	130	642	2,721	6,028	145	622
2018	Aug	2,114	5,214	179	744	2,821	6,439	144	618
2018	Sep	2,653	6,252	192	803	3,619	7,631	171	674
2018	Annual	2,577	5,746	236	899	2,851	6,879	181	756

Table 3-44 shows the average hourly number of up to congestion transactions and the average hourly MW in January 2017 through September 2018. In the first nine months of 2018, the average hourly up to congestion submitted and cleared MW decreased by 58.8 percent and 48.4 percent, compared to the first nine months of 2017.

Table 3-44 Average hourly cleared and submitted up to congestion bids by month: January 2017 through September 2018

		Up to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2017	Jan	39,639	196,472	2,466	10,246
2017	Feb	38,814	207,994	2,091	8,309
2017	Mar	31,817	164,063	1,703	6,252
2017	Apr	29,212	152,868	2,689	6,022
2017	May	32,883	116,688	2,977	4,957
2017	Jun	35,469	112,071	2,528	4,839
2017	Jul	37,668	118,609	2,413	5,108
2017	Aug	32,986	122,677	2,294	5,062
2017	Sep	29,368	120,956	2,309	4,423
2017	Oct	28,250	117,486	2,612	4,745
2017	Nov	36,506	110,325	2,927	4,679
2017	Dec	40,090	113,992	3,552	4,749
2017	Annual	34,387	137,419	2,549	5,770
2018	Jan	31,066	124,101	2,174	6,511
2018	Feb	25,543	94,687	1,857	4,703
2018	Mar	8,990	28,008	733	1,969
2018	Apr	11,930	43,989	877	2,001
2018	May	15,592	50,133	895	2,120
2018	Jun	15,227	46,207	827	1,794
2018	Jul	17,008	49,075	1,102	2,486
2018	Aug	17,658	53,077	997	2,317
2018	Sep	16,180	53,171	856	1,949
2018	Annual	17,639	60,036	1,142	2,863

Table 3-45 shows the average hourly number of import and export transactions and the average hourly MW in January 2017 through September 2018. In the first nine months of 2018, the average hourly submitted and cleared import transaction MW decreased by 28.9 and 35.7 percent, and the average hourly submitted and cleared export transaction MW decreased by 10.6 and 10.8 percent, compared to the first nine months of 2017. The large difference in net interchange volumes from the first nine months of 2017 to 2018 was primarily a result of the requirement for external capacity resources to be pseudo tied into PJM with the result that import MWh became internal MWh.[85]

Table 3-45 Hourly average day-ahead number of cleared and submitted import and export transactions by month: January 2017 through September 2018

		Imports				Exports			
Year	Month	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2017	Jan	1,465	1,505	8	9	3,842	3,855	20	20
2017	Feb	1,379	1,418	7	8	3,546	3,558	19	19
2017	Mar	1,125	1,157	6	7	3,791	3,813	18	18
2017	Apr	614	621	5	5	3,050	3,070	16	16
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	240	247	3	3	3,092	3,113	16	16
2017	Aug	158	168	2	3	2,401	2,410	12	13
2017	Sep	233	237	3	4	2,884	2,903	14	15
2017	Oct	211	218	3	3	2,293	2,301	12	12
2017	Nov	337	362	3	4	1,998	2,010	10	10
2017	Dec	324	386	3	5	3,193	3,245	15	15
2017	Annual	539	560	4	5	2,965	2,984	15	16
2018	Jan	541	640	8	10	2,531	2,567	13	13
2018	Feb	556	809	7	11	2,778	2,853	14	14
2018	Mar	578	612	7	8	1,895	1,892	10	11
2018	Apr	486	514	6	7	2,150	2,168	11	11
2018	May	382	404	5	6	2,495	2,506	15	15
2018	Jun	246	254	4	4	3,197	3,222	19	19
2018	Jul	260	260	4	5	3,014	3,027	15	15
2018	Aug	358	358	4	5	3,647	3,671	17	17
2018	Sep	230	230	4	4	3,384	3,390	17	17
2018	Annual	404	459	5	7	2,787	2,809	15	15

Table 3-46 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, 2017, through September 30, 2018.

85 *2018 Quarterly State of the Market Report for PJM: January through September*, Section 9: Interchange Transactions, Figure 9-1.

Table 3-46 Type of day-ahead marginal resources: January 2017 through September 2018

	2017						2018					
	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand
Jan	3.2%	0.0%	85.3%	7.7%	3.7%	0.0%	5.3%	0.1%	82.5%	7.4%	4.6%	0.0%
Feb	4.9%	0.0%	83.9%	6.5%	4.6%	0.0%	5.9%	0.1%	80.8%	9.1%	4.0%	0.0%
Mar	4.3%	0.1%	81.5%	8.5%	5.6%	0.0%	17.2%	0.2%	47.0%	20.4%	15.2%	0.0%
Apr	2.8%	0.0%	83.4%	8.9%	4.9%	0.0%	13.5%	0.1%	45.7%	24.1%	16.6%	0.0%
May	3.5%	0.0%	77.4%	11.8%	7.2%	0.0%	15.2%	0.1%	49.6%	24.0%	11.1%	0.0%
Jun	4.3%	0.0%	73.5%	15.4%	6.7%	0.0%	15.3%	0.1%	54.5%	20.8%	9.3%	0.0%
Jul	2.9%	0.0%	77.1%	13.6%	6.4%	0.0%	12.4%	0.1%	57.8%	19.0%	10.6%	0.1%
Aug	3.8%	0.0%	81.8%	9.0%	5.4%	0.0%	11.1%	0.2%	54.5%	22.5%	11.7%	0.0%
Sep	6.6%	0.0%	77.8%	9.8%	5.8%	0.0%	15.1%	0.2%	50.7%	20.5%	13.5%	0.0%
Oct	6.3%	0.0%	77.7%	10.3%	5.7%	0.0%						
Nov	5.1%	0.1%	78.7%	10.6%	5.6%	0.0%						
Dec	4.9%	0.1%	78.9%	10.8%	5.3%	0.0%						
Annual	4.3%	0.0%	79.9%	10.2%	5.5%	0.0%	10.7%	0.1%	63.9%	16.1%	9.2%	0.0%

Figure 3-39 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month from January 2005, through September 2018.

Figure 3-39 Monthly bid and cleared INCs, DECs and UTCs (MW): January 2005 through September 2018

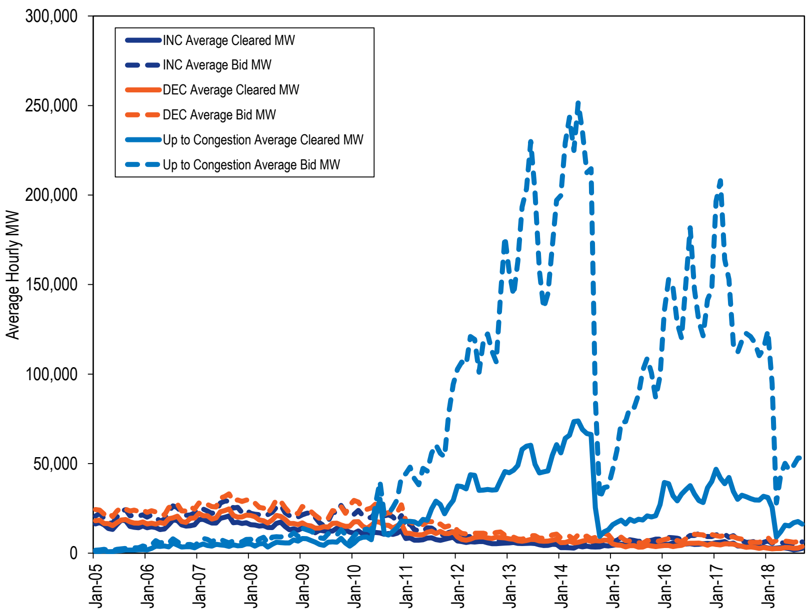
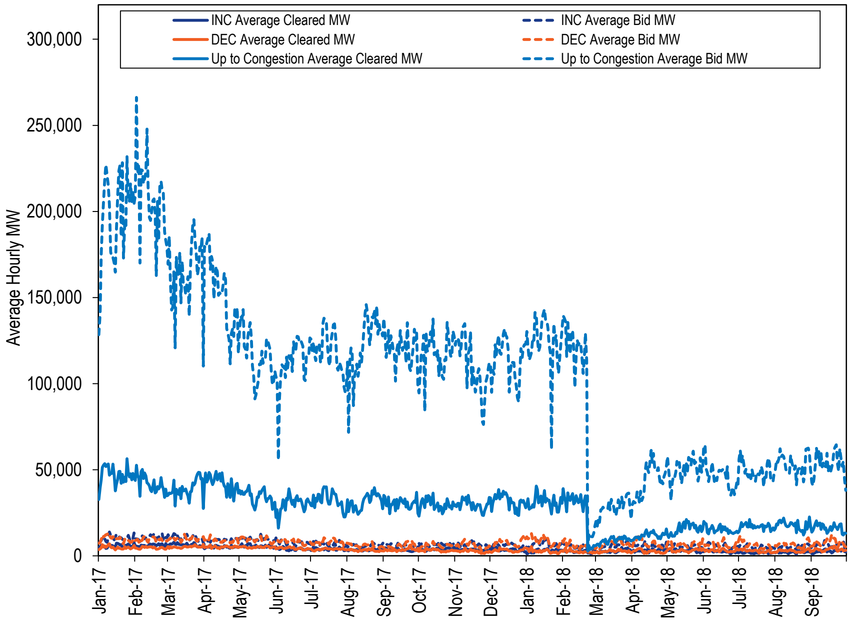


Figure 3-40 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 1, 2017 through September 30, 2018.

Figure 3-40 Daily bid and cleared INCs, DECs, and UTCs (MW): January 2017 through September 2018



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 3-47 shows, in the first nine months of 2017 and 2018, the total increment offers and decrement bids and cleared MW by type of parent organization.

Table 3-47 INC and DEC bids and cleared MWh by type of parent organization (MWh): January through September, 2017 and 2018

	Jan-Sep 2017				Jan-Sep 2018			
Category	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	73,202,724	68.1%	33,622,732	56.2%	70,600,376	85.4%	28,560,587	80.3%
Physical	34,277,537	31.9%	26,213,024	43.8%	12,025,457	14.6%	7,002,028	19.7%
Total	107,480,261	100.0%	59,835,756	100.0%	82,625,832	100.0%	35,562,615	100.0%

Table 3-48 shows, in the first nine months of 2017 and 2018, the total up to congestion bids and cleared MWh by type of parent organization.

Table 3-48 Up to congestion transactions by type of parent organization (MWh): January through September, 2017 and 2018

	Jan-Sep 2017				Jan-Sep 2018			
Category	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent
Financial	893,478,121	93.9%	218,476,434	91.5%	387,323,123	98.5%	111,087,700	96.1%
Physical	58,544,802	6.1%	20,416,217	8.5%	5,972,431	1.5%	4,464,400	3.9%
Total	952,022,923	100.0%	238,892,651	100.0%	393,295,554	100.0%	115,552,099	100.0%

Table 3-49 shows, in the first nine months of 2017 and 2018, the total import and export transactions by whether the parent organization was financial or physical.

Table 3-49 Import and export transactions by type of parent organization (MW): January through September, 2017 and 2018

		Jan-Sep 2017		Jan-Sep 2018	
	Category	Total Import and Export MW	Percent	Total Import and Export MW	Percent
Day-Ahead	Financial	9,725,219	39.7%	5,568,364	26.7%
	Physical	14,790,242	60.3%	15,310,354	73.3%
	Total	24,515,462	100.0%	20,878,718	100.0%
Real-Time	Financial	17,003,782	38.8%	8,303,270	21.4%
	Physical	26,834,587	61.2%	30,459,445	78.6%
	Total	43,838,369	100.0%	38,762,715	100.0%

Table 3-50 shows increment offers and decrement bids by top 10 locations in the first nine months of 2017 and 2018.

Table 3-50 Virtual offers and bids by top 10 locations (MW): January through September, 2017 and 2018

Jan-Sep 2017					Jan-Sep 2018				
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	16,303,266	12,276,948	28,580,213	WESTERN HUB	HUB	2,787,279	1,925,680	4,712,960
MISO	INTERFACE	221,785	5,278,718	5,500,503	NYIS	INTERFACE	1,025,671	886,127	1,911,798
AEP-DAYTON HUB	HUB	2,055,810	508,370	2,564,180	MISO	INTERFACE	233,928	1,675,483	1,909,410
NYIS	INTERFACE	1,232,270	1,042,835	2,275,104	SOUTHIMP	INTERFACE	1,854,658	0	1,854,658
N ILLINOIS HUB	HUB	457,428	1,689,308	2,146,736	BGE_RESID_AGG	RESIDUAL_METERED_EDC	194,428	1,082,290	1,276,717
SOUTHIMP	INTERFACE	1,999,033	0	1,999,033	DOM_RESID_AGG	RESIDUAL_METERED_EDC	284,444	897,596	1,182,040
FOWLER 34.5 KV FWLR1AWF	GEN	366,891	1,193,753	1,560,644	N ILLINOIS HUB	HUB	374,239	701,920	1,076,159
DCKCRKCE345 KV UN1 DYN	GEN	1,086,888	445,631	1,532,519	DOMINION HUB	HUB	179,653	866,464	1,046,117
BGE	ZONE	327,412	1,072,672	1,400,084	AEP-DAYTON HUB	HUB	386,544	582,995	969,539
PEPCO	ZONE	400,553	542,606	943,159	DCKCRKCE345 KV UN1 DYN	GEN	343,879	585,165	929,044
Top ten total		24,451,336	24,050,840	48,502,176			7,664,723	9,203,719	16,868,442
PJM total		55,822,362	54,691,593	110,513,955			37,641,430	45,061,722	82,703,151
Top ten total as percent of PJM total		43.8%	44.0%	43.9%			20.4%	20.4%	20.4%

Table 3-51 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 2017 and 2018.[86]

Table 3-51 Cleared up to congestion import bids by top 10 source and sink pairs (MW): January through September, 2017 and 2018

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%
Jan-Sep 2018							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	2,500,524	$836,289	$37,681	$873,970
NORTHWEST	INTERFACE	CHICAGO GEN HUB	HUB	2,033,306	$710,649	$5,210	$715,859
OVEC	INTERFACE	DEOK_RESID_AGG	AGGREGATE	1,362,961	$440,932	($298,884)	$142,048
NORTHWEST	INTERFACE	COMED_RESID_AGG	AGGREGATE	1,169,773	$1,074,659	($875,604)	$199,056
OVEC	INTERFACE	AEP GEN HUB	HUB	843,846	($66,957)	$212,391	$145,434
NORTHWEST	INTERFACE	CHICAGO HUB	HUB	808,011	$84,558	$82,739	$167,298
MISO	INTERFACE	CHICAGO GEN HUB	HUB	723,415	$449,862	$476,688	$926,550
OVEC	INTERFACE	ATSI GEN HUB	HUB	721,687	$337,504	($166,749)	$170,755
MISO	INTERFACE	CHICAGO HUB	HUB	627,608	$367,775	$84,105	$451,879
OVEC	INTERFACE	AEP-DAYTON HUB	HUB	522,205	$15,044	$253,241	$268,284
Top ten total				11,313,337	$4,250,315	($189,181)	$4,061,134
PJM total				26,914,216	$8,330,336	($68,016)	$8,262,321
Top ten total as percent of PJM total				42.0%	51.0%	278.1%	49.2%

86 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 3-52 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 2017 and 2018.

Table 3-52 Cleared up to congestion export bids by top 10 source and sink pairs (MW): January through September, 2017 and 2018

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)	$5,078,996
Top ten total as percent of PJM total				30.2%	51.0%	1,038.2%	28.9%
Jan-Sep 2018							
Exports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
CHICAGO GEN HUB	HUB	NIPSCO	INTERFACE	680,418	$810,686	$224,042	$1,034,728
COMED_RESID_AGG	AGGREGATE	NIPSCO	INTERFACE	578,424	$481,961	$916,736	$1,398,697
N ILLINOIS HUB	HUB	NIPSCO	INTERFACE	548,285	$764,912	$300,696	$1,065,608
JCPL_RESID_AGG	AGGREGATE	HUDSONTP	INTERFACE	258,375	($113,399)	($96,689)	($210,087)
CHICAGO HUB	HUB	NIPSCO	INTERFACE	211,817	$380,861	($180,976)	$199,886
OHIO HUB	HUB	NIPSCO	INTERFACE	188,956	($81,760)	$145,948	$64,188
AEP GEN HUB	HUB	OVEC	INTERFACE	138,239	($49,260)	($16,867)	($66,126)
AEPIM_RESID_AGG	AGGREGATE	NIPSCO	INTERFACE	136,319	($115,086)	$101,487	($13,599)
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	116,654	$445,574	($132,307)	$313,267
OHIO HUB	HUB	OVEC	INTERFACE	110,231	($984,471)	$827,450	($157,022)
Top ten total				2,967,716	$1,540,018	$2,089,522	$3,629,540
PJM total				9,502,839	($3,140,628)	$7,042,564	$3,901,936
Top ten total as percent of PJM total				31.2%	(49.0%)	29.7%	93.0%

Table 3-53 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 2017 and 2018.

Table 3-53 Cleared up to congestion wheel bids by top 10 source and sink pairs (MW): January through September, 2017 and 2018

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%
Jan-Sep 2018							
Wheels							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	NIPSCO	INTERFACE	1,066,046	$1,798,781	($134,396)	$1,664,385
MISO	INTERFACE	NORTHWEST	INTERFACE	782,843	$262,002	$138,497	$400,498
NORTHWEST	INTERFACE	MISO	INTERFACE	407,681	$501,015	($133,475)	$367,540
OVEC	INTERFACE	SOUTHEXP	INTERFACE	301,253	$446,672	($311,658)	$135,014
SOUTHIMP	INTERFACE	OVEC	INTERFACE	256,444	($1,278,349)	$1,215,496	($62,853)
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	253,579	$42,045	$431,202	$473,248
SOUTHIMP	INTERFACE	NIPSCO	INTERFACE	176,893	($581,953)	$841,593	$259,640
OVEC	INTERFACE	NIPSCO	INTERFACE	174,708	($438,676)	$349,383	($89,293)
MISO	INTERFACE	OVEC	INTERFACE	172,159	$209,829	($184,572)	$25,257
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	143,660	$558,551	$31,300	$589,850
Top ten total				3,735,266	$1,519,916	$2,243,370	$3,763,286
PJM total				5,077,005	$1,580,897	$2,117,845	$3,698,743
Top ten total as percent of PJM total				73.6%	96.1%	105.9%	101.7%

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 5.9 percent of the PJM total internal up to congestion transactions MW in the first nine months of 2018.

Table 3-54 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 2017 and 2018. The total UTC profit by top 10 locations decreased by $1.0 million, from $1.9 million in the first nine months of 2017 to $0.9 million in the first nine months of 2018. The total internal cleared MW decreased by 129.8 million MW, or 63.7 percent, from 203.8 million MW in the first nine months of 2017 to 74.1 million MW in the first nine months of 2018.

Table 3-54 Cleared up to congestion internal bids by top 10 source and sink pairs (MW): January through September, 2017 and 2018

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	$61,135,226	($34,975,388)	$26,159,839
Top ten total as percent of PJM total				5.5%	5.3%	3.9%	7.2%
Jan-Sep 2018							
Internal							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
WESTERN HUB	HUB	N ILLINOIS HUB	HUB	1,218,355	$751,591	($1,054,714)	($303,123)
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	828,418	$207,187	($23,401)	$183,785
AEP GEN HUB	HUB	FEOHIO_RESID_AGG	AGGREGATE	718,784	$334,502	$442,483	$776,985
CHICAGO HUB	HUB	COMED_RESID_AGG	AGGREGATE	658,496	$1,355,347	($1,284,070)	$71,277
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	625,073	($87,925)	$358,785	$270,860
ATSI GEN HUB	HUB	FEOHIO_RESID_AGG	AGGREGATE	623,343	($217,567)	$556,418	$338,852
AECO_RESID_AGG	AGGREGATE	VINELAND_RESID_AGG	AGGREGATE	604,955	($251,565)	($166,358)	($417,923)
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	584,448	$101,911	$9,916	$111,827
DOM_RESID_AGG	AGGREGATE	DOMINION HUB	HUB	573,175	$1,690,631	($1,460,111)	$230,521
PPL_RESID_AGG	AGGREGATE	METED_RESID_AGG	AGGREGATE	456,015	$847,488	($1,210,388)	($362,900)
Top ten total				6,891,061	$4,731,599	($3,831,440)	$900,160
PJM total				74,058,040	($12,718,252)	$28,078,367	$15,360,114
Top ten total as percent of PJM total				9.3%	(37.2%)	(13.6%)	5.9%

Table 3-55 shows the number of source-sink pairs that were offered and cleared monthly for January 1, 2017 through September 30, 2018.

Table 3-55 Number of offered and cleared source and sink pairs: January 2017 through September 2018

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
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	7,936	9,117	6,477	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	Oct	8,540	9,432	6,507	7,189
2017	Nov	8,027	9,665	6,273	7,444
2017	Dec	7,782	8,872	5,892	6,771
2017	Annual	9,392	10,928	6,385	7,212
2018	Jan	7,983	8,492	5,658	6,481
2018	Feb	5,909	8,299	4,559	6,398
2018	Mar	1,399	1,736	1,088	1,461
2018	Apr	1,479	1,608	1,240	1,388
2018	May	1,345	1,426	1,148	1,221
2018	Jun	1,411	1,563	1,236	1,350
2018	Jul	1,727	2,159	1,457	1,796
2018	Aug	1,816	2,124	1,463	1,703
2018	Sep	1,424	1,559	1,208	1,326
2018	Jan-Sep	2,722	3,218	2,117	2,569

Table 3-56 and Figure 3-41 show total cleared up to congestion transactions by type in the first nine months of 2017 and 2018. Total up to congestion transactions in 2017 decreased by 51.6 percent from 238.9 million MW in the first nine months of 2017 to 115.6 million MW in the first nine months of 2018. Internal up to congestion transactions in the first nine months of 2018 were 64.1 percent of all up to congestion transactions compared to 85.3 percent in the first nine months of 2017.

Table 3-56 Cleared up to congestion transactions by type (MW): January through September, 2017 and 2018

	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%
	Jan-Sep 2018				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	11,313,337	2,967,716	3,735,266	6,891,061	24,907,380
PJM total (MW)	26,914,216	9,502,839	5,077,005	74,058,040	115,552,100
Top ten total as percent of PJM total	42.0%	31.2%	73.6%	9.3%	21.6%
PJM total as percent of all up to congestion transactions	23.3%	8.2%	4.4%	64.1%	100.0%

Figure 3-41 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 15 month refund period for the proceeding related to uplift charges for UTC transactions.[87] But in the first nine months of 2018, the percent of marginal up to congestion transactions again decreased significantly as the result of a FERC order issued on February 20, 2018 and implemented on February 22, 2018.[88] The order limited UTC trading to hubs, residual metered load, and interfaces. The reduction in UTC bid locations effective February 22, 2018, resulted in a significant reduction in total activity.

87 *Id.*
88 162 FERC ¶ 61,139 (2018).

Figure 3-41 Monthly cleared up to congestion transactions by type (MW): January 2005 through September 2018

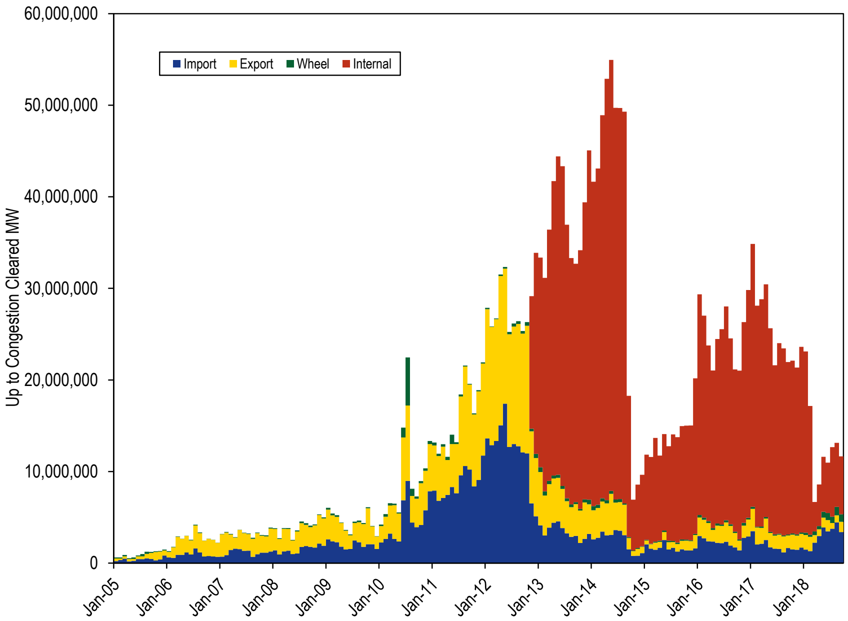
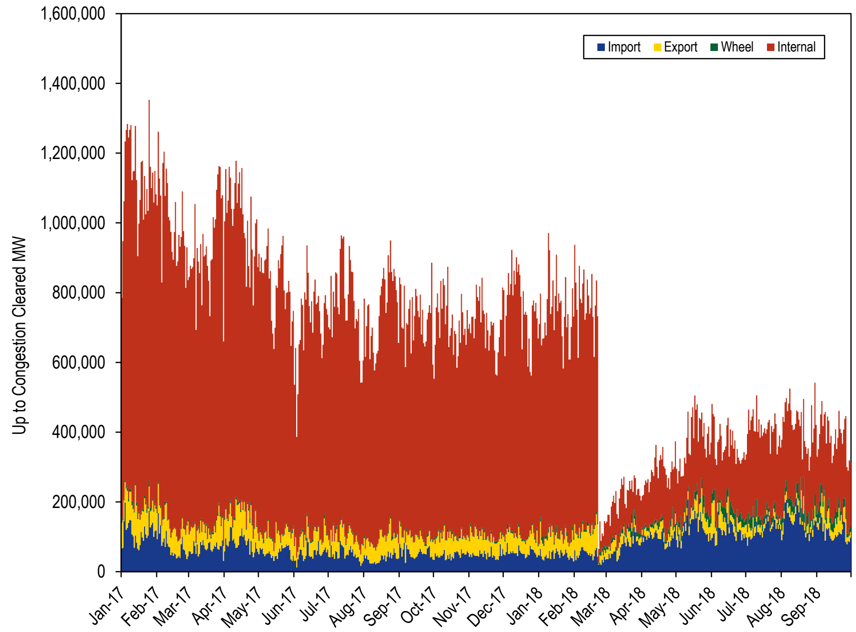


Figure 3-42 shows the daily cleared up to congestion MW by transaction type from January 1, 2017 through September 30, 2018.

Figure 3-42 Daily cleared up to congestion transaction by type (MW): January 2017 through September 2018



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 markups are not marginal by altering the economic dispatch order of supply.

The MMU calculates an explicit measure of the impact of marginal unit incremental energy offer markups on LMP using the mathematical relationships among LMPs in the market solution.[89] 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.

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 3-57 shows the impact (markup component of LMP) of the marginal unit 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 $4.82 per MWh in the first nine months of 2017 to $7.88 per MWh in the first nine months of 2018. The adjusted markup contribution of coal units in the first nine months of 2018 was $2.24 per MWh. The adjusted markup component of gas fired units in the first nine months of 2018 was $4.92 per MWh, an increase of $1.55 per MWh from the first nine months of 2017. The markup component of wind units was $0.01 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 2018, among the wind units that were marginal, 72.5 percent had negative offer prices.

89 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 incremental energy offer and the cost-based incremental energy 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. The markup analysis does not include markup in start up or no load offers. *See* Calculation and Use of Generator Sensitivity/Unit Participation Factors, 2010 State of the Market Report for PJM: Technical Reference for PJM Markets.

Table 3-57 Markup component of real-time, load-weighted, average LMP by primary fuel type and unit type: January through September, 2017 and 2018[90]

		2017 (Jan - Sep)		2018 (Jan - Sep)	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	$0.24	$1.29	$1.36	$2.24
Gas	CC	$1.85	$2.85	$2.94	$4.14
Gas	CT	$0.24	$0.41	$0.34	$0.67
Gas	Diesel	($0.00)	$0.00	$0.00	$0.01
Gas	Steam	$0.03	$0.11	$0.02	$0.10
Municipal Waste	CT	$0.00	$0.00	$0.00	$0.00
Municipal Waste	Diesel	$0.00	$0.00	$0.00	$0.00
Municipal Waste	Steam	$0.00	$0.00	$0.00	$0.00
Oil	CC	$0.00	$0.00	$0.20	$0.22
Oil	CT	$0.01	$0.04	$0.07	$0.23
Oil	Diesel	$0.00	$0.00	$0.00	$0.00
Oil	Steam	($0.00)	$0.00	$0.13	$0.17
Other		$0.02	$0.02	$0.09	$0.09
Uranium		$0.00	$0.00	$0.00	$0.00
Wind		$0.09	$0.09	$0.01	$0.01
Total		$2.49	$4.82	$5.15	$7.88

Markup Component of Real-Time Price

Table 3-58 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-59 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 2018, when using unadjusted cost-based offers, $5.15 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-based offers, $7.88 per MWh of the PJM real-time load-weighted, average LMP was attributable to markup. In the first nine months of 2018, the off peak markup component was highest in January, $11.65 per MWh using unadjusted cost-based offers and $17.60 per MWh using adjusted cost-based offers. This corresponds to 13.28 percent and 20.07 percent of the real-time off peak load-weighted average LMP in January.

90 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 3-58 Monthly markup components of real-time load-weighted LMP (Unadjusted): 2017 and 2018

	2017			2018		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$1.75	$0.47	$3.11	$9.29	$11.65	$6.89
Feb	$1.47	$0.53	$2.36	$1.47	$0.95	$1.97
Mar	$1.10	$1.70	$0.55	$4.94	$2.68	$7.15
Apr	$1.87	$0.93	$2.86	$5.71	$3.47	$7.92
May	$2.91	($0.01)	$5.51	$5.20	$1.57	$8.45
Jun	$3.08	$0.93	$4.88	$2.86	$1.96	$3.69
Jul	$3.62	$2.16	$5.12	$4.84	$1.50	$8.01
Aug	$2.87	$1.51	$3.94	$4.81	$1.94	$7.12
Sep	$3.42	$1.46	$5.35	$6.55	$3.71	$9.63
Total	$2.49	$1.11	$3.78	$5.15	$3.44	$6.79

Table 3-59 Monthly markup components of real-time load-weighted LMP (Adjusted): 2017 and 2018

	2017			2018		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$4.43	$3.07	$5.88	$14.99	$17.60	$12.33
Feb	$3.66	$2.60	$4.67	$3.64	$2.96	$4.32
Mar	$3.56	$3.82	$3.33	$7.28	$4.89	$9.63
Apr	$4.01	$2.95	$5.12	$8.16	$5.73	$10.56
May	$5.33	$2.07	$8.23	$7.38	$3.48	$10.86
Jun	$5.29	$2.85	$7.33	$4.94	$3.87	$5.95
Jul	$6.08	$4.29	$7.92	$7.21	$3.61	$10.62
Aug	$5.06	$3.43	$6.35	$7.24	$4.16	$9.71
Sep	$5.57	$3.37	$7.73	$8.92	$5.85	$12.25
Total	$4.82	$3.21	$6.33	$7.88	$6.03	$9.64

Hourly Markup Component of Real-Time Prices

Figure 3-43 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in the first nine months of 2018 and 2017. Figure 3-44 shows the markup contribution to the hourly load-weighted LMP using adjusted cost-based offers in the first nine months of 2018 and 2017. The hourly markup component of real-time prices was higher during the first eight days of January 2018, when the PJM region experienced particularly low temperatures.

Figure 3-43 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): January through September, 2017 and 2018

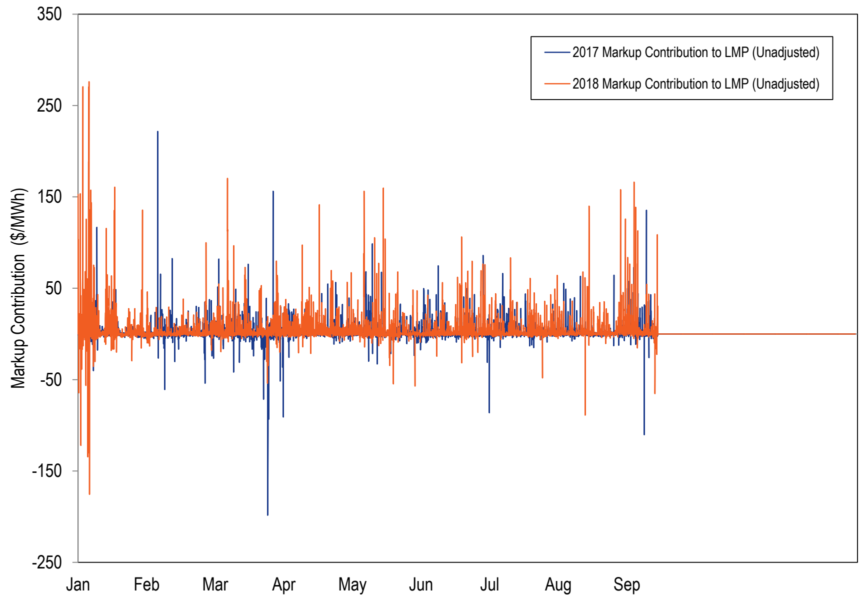
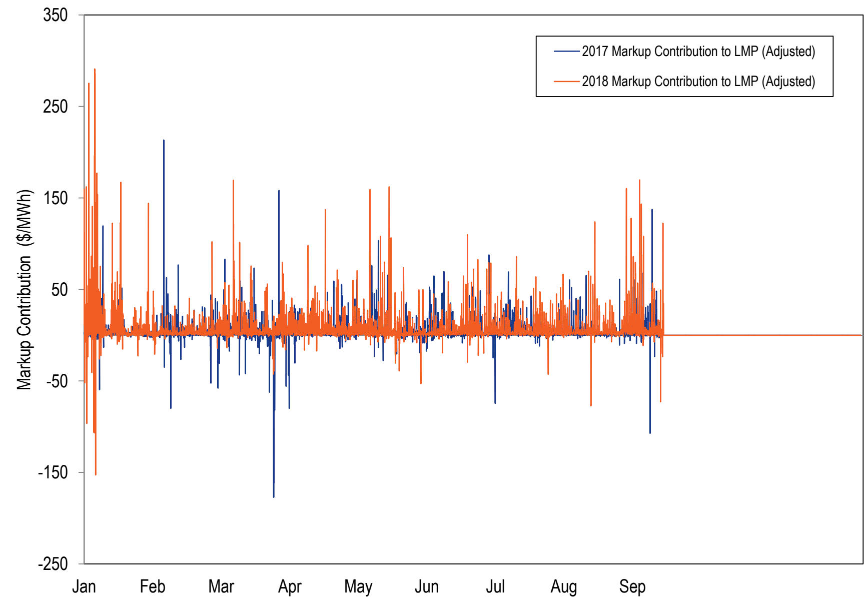


Figure 3-44 Markup contribution to real-time hourly load-weighted LMP (Adjusted): January through September, 2017 and 2018



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 2017 and 2018 in Table 3-60 and for adjusted offers in Table 3-61. The smallest zonal all hours average markup component using unadjusted offers in the first nine months of 2018 was in the ComEd Control Zone, 3.64 per MWh, while the highest was in the BGE Control Zone, $6.90 per MWh. The smallest zonal on peak average markup component using unadjusted offers in the first nine months of 2018 was in the PSEG Control Zone, 5.26 per MWh, while the highest was in the BGE Control Zone, $9.49 per MWh.

Table 3-60 Average real-time zonal markup component (Unadjusted): January through September, 2017 and 2018

	2017 (Jan - Sep)			2018 (Jan - Sep)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$2.31	$1.20	$3.38	$4.63	$3.49	$5.72
AEP	$2.24	$1.04	$3.39	$4.90	$3.34	$6.42
APS	$2.38	$1.04	$3.68	$5.60	$3.72	$7.43
ATSI	$2.44	$1.04	$3.73	$6.18	$3.66	$8.56
BGE	$3.24	$1.63	$4.77	$6.90	$4.18	$9.49
ComEd	$2.30	$0.90	$3.57	$3.64	$1.72	$5.45
DAY	$2.31	$1.10	$3.42	$5.21	$3.26	$7.01
DEOK	$2.35	$1.09	$3.54	$5.31	$3.51	$7.04
DLCO	$2.40	$1.01	$3.70	$6.38	$3.89	$8.77
DPL	$2.61	$1.47	$3.69	$5.15	$3.81	$6.44
Dominion	$2.92	$1.33	$4.45	$6.30	$4.86	$7.71
EKPC	$2.22	$1.04	$3.40	$4.83	$3.75	$5.91
JCPL	$2.76	$1.20	$4.18	$4.50	$3.44	$5.46
Met-Ed	$2.36	$0.89	$3.70	$4.79	$3.34	$6.14
PECO	$2.21	$1.06	$3.28	$4.50	$3.11	$5.80
PENELEC	$2.29	$1.15	$3.34	$5.11	$3.21	$6.90
PPL	$2.34	$0.81	$3.76	$4.30	$2.85	$5.65
PSEG	$2.66	$1.15	$4.05	$4.26	$3.19	$5.26
Pepco	$2.86	$1.37	$4.23	$6.14	$4.09	$8.04
RECO	$2.93	$1.58	$4.07	$4.70	$3.21	$5.97

Table 3-61 Average real-time zonal markup component (Adjusted): January through September, 2017 and 2018

	2017 (Jan - Sep)			2018 (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	$4.56	$3.18	$5.89	$7.22	$5.95	$8.43
AEP	$4.56	$3.17	$5.90	$7.55	$5.84	$9.21
APS	$4.74	$3.17	$6.24	$8.48	$6.47	$10.44
ATSI	$4.89	$3.23	$6.43	$8.91	$6.16	$11.51
BGE	$5.74	$3.80	$7.58	$10.08	$7.21	$12.82
ComEd	$4.50	$2.89	$5.97	$5.95	$3.89	$7.88
DAY	$4.73	$3.27	$6.05	$7.86	$5.71	$9.84
DEOK	$4.65	$3.19	$6.01	$7.84	$5.89	$9.72
DLCO	$4.77	$3.15	$6.30	$9.10	$6.34	$11.74
DPL	$5.00	$3.66	$6.28	$8.16	$6.59	$9.65
Dominion	$5.30	$3.50	$7.03	$9.42	$7.97	$10.83
EKPC	$4.51	$3.16	$5.85	$7.38	$6.13	$8.63
JCPL	$5.04	$3.20	$6.71	$7.18	$5.99	$8.25
Met-Ed	$4.72	$2.88	$6.41	$7.38	$5.79	$8.85
PECO	$4.42	$3.04	$5.71	$7.17	$5.64	$8.59
PENELEC	$4.64	$3.27	$5.91	$7.77	$5.66	$9.76
PPL	$4.59	$2.82	$6.25	$6.90	$5.39	$8.32
PSEG	$4.95	$3.13	$6.62	$6.88	$5.67	$7.99
Pepco	$5.28	$3.51	$6.92	$9.28	$7.14	$11.29
RECO	$5.27	$3.63	$6.66	$7.26	$5.62	$8.66

Markup by Real Time Price Levels

Table 3-62 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 3-62 Average real-time markup component (By price category, unadjusted): January through September, 2017 and 2018

	2017 (Jan - Sep)		2018 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.08)	49.1%	($0.11)	40.3%
$25 to $50	$1.18	45.3%	$1.79	47.3%
$50 to $75	$0.91	4.4%	$1.41	6.4%
$75 to $100	$0.29	0.8%	$0.54	2.1%
$100 to $125	$0.11	0.2%	$0.53	1.5%
$125 to $150	$0.00	0.1%	$0.19	0.7%
>= $150	$0.11	0.2%	$0.95	1.7%

Table 3-63 Average real-time markup component (By price category, adjusted): January through September, 2017 and 2018

	2017 (Jan - Sep)		2018 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$0.75	49.1%	$0.56	40.3%
$25 to $50	$2.48	45.3%	$3.09	47.3%
$50 to $75	$1.09	4.3%	$1.65	6.4%
$75 to $100	$0.33	0.8%	$0.66	2.1%
$100 to $125	$0.12	0.2%	$0.65	1.5%
$125 to $150	$0.01	0.1%	$0.26	0.7%
>= $150	$0.11	0.2%	$1.22	1.7%

Day-Ahead Markup

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

The markup component of the PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 3-64. INC, DEC and up to congestion transactions (UTC) have zero markups. INCs were 9.2 percent of marginal resources and DECs were 16.1 percent of marginal resources in the first nine months of 2018. 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 76.1 percent in 2015 to 82.4 percent in 2016 due to the expiration of the 15 months resettlement period for the proceeding related to uplift charges for UTC transactions. The share of marginal up to congestion transactions decreased from 80.4 percent in first nine months of 2017 to 63.9 percent in first nine months of 2018 as the result of a FERC order issued on February 20, 2018, and implemented on February 22, 2018.[91] The order limited UTC trading to hubs, residual metered load, and interfaces.

The adjusted markup of coal, gas and oil units is calculated as the difference between the price-based offer, and the cost-based offer excluding the 10 percent adder. Table 3-64 shows the markup component of LMP for marginal generating resources. Generating resources were only 10.7 percent of marginal resources in first nine months of 2018. Using adjusted cost-based offers, the markup component of LMP for marginal generating resources increased for coal fired steam units from $0.87 to $1.36 and increased for gas fired CT units from $0.08 to $0.13. The markup component of LMP for coal fired steam units increased from $0.15 in first nine months of 2017 to $0.65 in first nine months of 2018 using unadjusted cost-based offers. The markup component of LMP for gas fired steam units decreased from $0.47 in first nine months of 2017 to $0.25 in first nine months of 2018 using unadjusted cost-based offers.

91 162 FERC ¶ 61,139 (2018).

Table 3-64 Markup component of day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through September, 2017 and 2018

		2017 (Jan - Sep)			2018 (Jan - Sep)		
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency
Coal	Steam	$0.15	$0.87	42.9%	$0.65	$1.36	43.7%
Gas	CT	$0.04	$0.08	2.7%	$0.05	$0.13	3.4%
Gas	Diesel	$0.00	$0.00	0.6%	$0.00	$0.00	0.7%
Gas	Steam	$0.47	$1.00	40.8%	$0.25	$0.91	46.9%
Oil	CT	($0.00)	$0.00	5.5%	$0.00	$0.00	0.5%
Oil	Diesel	$0.00	($0.00)	0.4%	$0.00	$0.00	0.0%
Oil	Steam	$0.00	$0.00	0.0%	($0.28)	($0.15)	0.8%
Other	Solar	$0.00	$0.00	0.0%	$0.00	$0.00	0.3%
Other	Steam	$0.01	$0.01	0.1%	($0.00)	($0.00)	0.1%
Uranium	Steam	$0.00	$0.00	1.9%	$0.00	$0.00	1.5%
Water	Hydro	$0.00	$0.00	0.3%	$0.00	$0.00	0.0%
Wind	Wind	$0.01	$0.01	4.7%	$0.01	$0.01	2.0%
Total		$0.68	$1.97	100.0%	$0.67	$2.27	100.0%

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 3-65 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted cost-based offers. In first nine months of 2018, when using unadjusted cost-based offers, $0.67 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In first nine months of 2018, the peak markup component was highest in January, $4.04 per MWh using unadjusted cost-based offers.

Table 3-65 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January 2017 through September 2018

	2017			2018		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	($0.03)	$0.19	($0.23)	$0.87	$4.04	($2.29)
Feb	$0.25	$0.59	($0.10)	$0.83	$1.58	$0.05
Mar	$0.38	$0.83	($0.12)	$0.65	$0.97	$0.32
Apr	$0.82	$1.64	$0.03	$1.03	$1.60	$0.46
May	$0.45	$1.07	($0.25)	$0.74	$1.29	$0.12
Jun	$0.90	$1.35	$0.35	($0.34)	$0.14	($0.87)
Jul	$0.60	$1.12	$0.09	$0.34	$0.93	($0.30)
Aug	$1.13	$1.94	$0.09	$0.51	$1.04	($0.18)
Sep	$1.65	$2.72	$0.57	$1.55	$2.77	$0.42
Oct	$1.71	$2.69	$0.64			
Nov	($0.08)	($0.23)	$0.08			
Dec	$0.90	$1.60	$0.29			
Annual	$0.72	$1.29	$0.12	$0.67	$1.59	($0.30)

Table 3-66 shows the markup component of average prices and of average monthly on peak and off peak prices using adjusted cost-based offers. In first nine months of 2018, when using adjusted cost-based offers, $2.27 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In first nine months of 2018, the peak markup component was highest in January, $7.25 per MWh using adjusted cost-based offers.

Table 3-66 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: January 2017 through September 2018

	2017			2018		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$1.40	$1.49	$1.32	$4.23	$7.25	$1.23
Feb	$1.65	$1.89	$1.39	$2.43	$3.26	$1.57
Mar	$1.65	$1.99	$1.27	$1.95	$2.22	$1.67
Apr	$1.94	$2.50	$1.41	$2.12	$2.55	$1.67
May	$1.62	$2.05	$1.14	$1.92	$2.31	$1.47
Jun	$2.40	$2.96	$1.71	$1.18	$1.53	$0.79
Jul	$1.73	$1.96	$1.50	$1.78	$2.28	$1.24
Aug	$2.40	$3.09	$1.52	$1.89	$2.24	$1.45
Sep	$2.98	$3.99	$1.96	$2.79	$3.83	$1.82
Oct	$2.88	$3.76	$1.92			
Nov	$1.33	$1.13	$1.53			
Dec	$2.52	$3.10	$2.03			
Annual	$2.04	$2.50	$1.56	$2.27	$3.07	$1.43

Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted cost-based offers is shown for each zone in Table 3-67. The markup component of annual average day-ahead price using adjusted cost-based offers is shown for each zone in Table 3-68. The smallest zonal all hours average markup component using adjusted cost-based offers for first nine months of 2018 was in the DPL Zone, $1.89 per MWh, while the highest was in the DEOK Control Zone, $2.80 per MWh. The smallest zonal on peak average markup using adjusted cost-based offers was in the DPL Control Zone, $2.64 per MWh, while the highest was in the EKPC Control Zone, $3.89 per MWh.

Table 3-67 Day-ahead, average, zonal markup component (Unadjusted): January through September, 2017 and 2018

	2017 (Jan - Sep)			2018 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$1.08	$1.78	$0.34	$0.57	$1.25	($0.16)
AEP	$0.65	$1.30	($0.03)	$0.95	$1.76	$0.11
APS	$0.60	$1.18	($0.02)	$0.38	$1.45	($0.74)
ATSI	$0.65	$1.25	($0.03)	$0.68	$1.61	($0.34)
BGE	$0.52	$1.06	($0.07)	$0.31	$1.58	($1.04)
ComEd	$0.47	$0.90	($0.01)	$0.84	$1.55	$0.08
DAY	$0.71	$1.38	($0.03)	$0.68	$1.61	($0.34)
DEOK	$0.79	$1.53	($0.01)	$1.35	$2.24	$0.40
DLCO	$0.65	$1.25	($0.00)	$1.11	$2.41	($0.28)
Dominion	$0.62	$1.25	($0.04)	$0.35	$1.56	($0.89)
DPL	$0.86	$1.37	$0.31	$0.14	$1.04	($0.83)
EKPC	$0.59	$1.14	$0.03	$1.22	$2.38	$0.06
JCPL	$0.95	$1.51	$0.33	$0.63	$1.38	($0.21)
Met-Ed	$1.04	$1.81	$0.19	$0.61	$1.52	($0.39)
PECO	$0.90	$1.49	$0.28	$0.49	$1.19	($0.25)
PENELEC	$0.64	$1.23	$0.03	$1.07	$1.41	$0.69
Pepco	$0.58	$1.19	($0.07)	$0.21	$1.40	($1.08)
PPL	$0.88	$1.48	$0.23	$0.80	$1.43	$0.13
PSEG	$0.95	$1.55	$0.29	$0.57	$1.49	($0.47)
RECO	$1.04	$1.65	$0.34	$0.44	$1.47	($0.76)

Table 3-68 Day-ahead, average, zonal markup component (Adjusted): January through September, 2017 and 2018

	2017 (Jan - Sep)			2018 (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	$2.39	$2.98	$1.76	$2.34	$2.95	$1.69
AEP	$1.96	$2.49	$1.41	$2.44	$3.13	$1.73
APS	$1.90	$2.35	$1.42	$1.98	$2.87	$1.06
ATSI	$1.97	$2.46	$1.43	$2.20	$2.99	$1.35
BGE	$1.85	$2.26	$1.40	$2.07	$3.16	$0.90
ComEd	$1.70	$2.02	$1.34	$2.22	$2.89	$1.51
DAY	$2.05	$2.61	$1.43	$2.23	$3.02	$1.36
DEOK	$2.06	$2.67	$1.40	$2.80	$3.64	$1.92
DLCO	$1.93	$2.39	$1.42	$2.51	$3.57	$1.38
Dominion	$1.94	$2.45	$1.42	$2.07	$3.10	$1.01
DPL	$2.18	$2.56	$1.77	$1.89	$2.64	$1.09
EKPC	$1.87	$2.28	$1.44	$2.78	$3.89	$1.66
JCPL	$2.24	$2.67	$1.75	$2.39	$3.05	$1.64
Met-Ed	$2.34	$3.01	$1.60	$2.32	$3.12	$1.44
PECO	$2.20	$2.66	$1.71	$2.27	$2.87	$1.62
PENELEC	$1.91	$2.37	$1.42	$2.63	$2.93	$2.30
Pepco	$1.91	$2.40	$1.39	$1.95	$2.97	$0.83
PPL	$2.17	$2.65	$1.65	$2.52	$3.06	$1.96
PSEG	$2.22	$2.67	$1.72	$2.31	$3.11	$1.40
RECO	$2.30	$2.77	$1.76	$2.16	$3.07	$1.09

Markup by Day-Ahead Price Levels

Table 3-69 and Table 3-70 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 3-69 Average, day-ahead markup component (By LMP category, unadjusted): January through September, 2017 and 2018

	2017 (Jan - Sep)		2018 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.10)	45.4%	($0.14)	32.6%
$25 to $50	$0.57	51.4%	$0.44	55.9%
$50 to $75	$0.16	2.5%	$0.30	6.1%
$75 to $100	$0.04	0.4%	$0.02	2.2%
$100 to $125	$0.00	0.1%	$0.08	1.2%
$125 to $150	($0.00)	0.0%	$0.06	0.8%
>= $150	$0.02	0.1%	($0.09)	1.2%

Table 3-70 Average, day-ahead markup component (By LMP category, adjusted): January through September, 2017 and 2018

	2017 (Jan - Sep)		2018 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$0.44	45.4%	$0.28	32.6%
$25 to $50	$1.26	51.4%	$1.26	55.9%
$50 to $75	$0.20	2.5%	$0.37	6.1%
$75 to $100	$0.04	0.4%	$0.09	2.2%
$100 to $125	($0.00)	0.1%	$0.13	1.2%
$125 to $150	($0.00)	0.0%	$0.10	0.8%
>= $150	$0.02	0.1%	$0.04	1.2%

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 29.9 percent and 27.9 percent higher in the first nine months of 2018 than in the first nine months of 2017.

PJM real-time energy market prices increased in the first nine months of 2018 compared to the first nine months of 2017. The average LMP was 26.8 percent higher in the first nine months of 2018 than in the first nine months of 2017, $36.52 per MWh versus $28.79 per MWh. The load-weighted average LMP was 29.9 percent higher in the first nine months of 2018 than in the first nine months of 2017, $39.43 per MWh versus $30.36 per MWh.

The real-time load-weighted average LMP for the first nine months of 2018 was 17.7 percent higher than the real-time fuel-cost adjusted, load-weighted, average LMP for the first nine months of 2018. If fuel and emission costs in the first nine months of 2018 had been the same as in the first nine months of 2017, holding everything else constant, the load-weighted LMP would have been lower, $33.51 per MWh instead of the observed $39.43 per MWh.

PJM day-ahead energy market prices increased in the first nine months of 2018 compared to the first nine months of 2017. The day-ahead average LMP was 24.7 percent higher in the first nine months of 2018 than in the first nine months of 2017, $36.04 per MWh versus $28.90 per MWh. The day-ahead load-weighted average LMP was 27.9 percent higher in the first nine months of 2018 than in the first nine months of 2017, $38.71 per MWh versus $30.26 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.[92] In the nodal pricing system, the LMP at a pricing node is the total cost of meeting incremental demand at that node. When there are binding transmission constraints, satisfying the marginal increase in demand at a node may require increasing the output of some generators while simultaneously decreasing the output of other generators, such that the transmission constraints are not violated. The total cost of redispatching multiple generators can at times exceed the cost of marginally increasing the output of the most expensive generator offered. Thus, the LMPs at some pricing nodes exceed $1,000 per MWh, the cap on the generators' offer price in the PJM market.[93]

Real-Time LMP

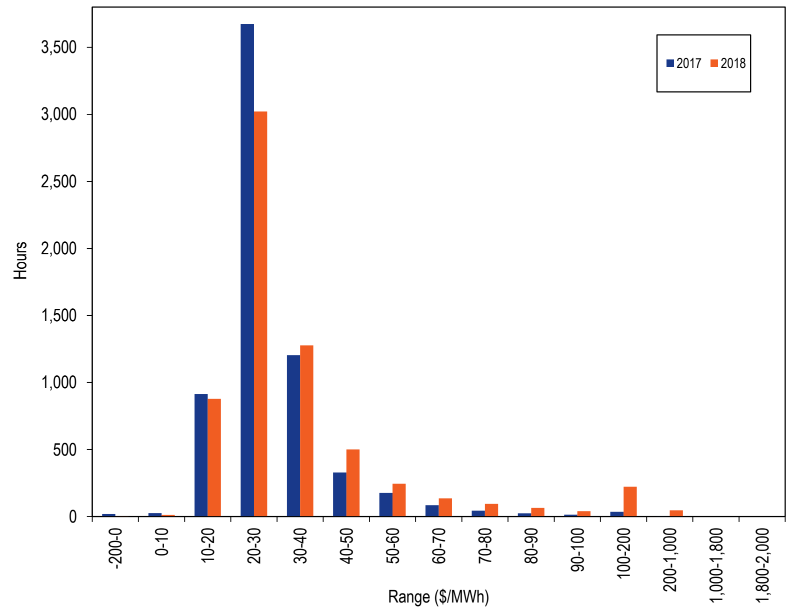
Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[94]

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 3-45 shows the hourly distribution of PJM real-time average LMP for the first nine months of 2017 and 2018.

Figure 3-45 Average LMP for the Real-Time Energy Market: January through September, 2017 and 2018



92 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.

93 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).

94 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 3-71 shows the PJM real-time, average LMP for the first nine months of 1998 through 2018.[95]

Table 3-71 Real-time, average LMP (Dollars per MWh): January through September, 1998 through 2018

	Real-Time LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$17.51	$15.30	$7.84	NA	NA	NA
1999	$18.79	$16.56	$7.29	7.3%	8.3%	(7.0%)
2000	$23.66	$17.73	$16.22	25.9%	7.0%	122.4%
2001	$33.77	$26.01	$20.79	42.8%	46.8%	28.2%
2002	$22.23	$19.22	$9.61	(34.2%)	(26.1%)	(53.8%)
2003	$49.57	$43.08	$30.54	123.0%	124.2%	217.9%
2004	$46.37	$41.04	$24.07	(6.5%)	(4.8%)	(21.2%)
2005	$46.51	$40.62	$22.07	0.3%	(1.0%)	(8.3%)
2006	$52.98	$46.15	$23.29	13.9%	13.6%	5.5%
2007	$55.34	$47.15	$33.29	4.5%	2.2%	43.0%
2008	$66.75	$57.05	$35.54	20.6%	21.0%	6.8%
2009	$47.29	$40.56	$21.99	(29.2%)	(28.9%)	(38.1%)
2010	$44.13	$37.82	$21.87	(6.7%)	(6.8%)	(0.6%)
2011	$44.76	$38.14	$23.10	1.4%	0.8%	5.6%
2012	$30.38	$28.82	$11.63	(32.1%)	(24.4%)	(49.7%)
2013	$36.33	$32.29	$18.47	19.6%	12.1%	58.9%
2014	$52.72	$36.06	$74.17	45.1%	11.7%	301.6%
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%
2018	$36.52	$27.26	$33.22	26.8%	7.8%	97.6%

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.

95 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.

PJM Real-Time, Load-Weighted, Average LMP

Table 3-72 shows the PJM real-time, load-weighted, average LMP in the first nine months of 1998 through 2018.

Table 3-72 Real-time, load-weighted, average LMP (Dollars per MWh): January through September, 1998 through 2018

	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	36.4%	65.3%	(9.0%)
2004	$46.44	$43.03	$21.89	6.6%	12.7%	(17.5%)
2005	$60.44	$50.10	$36.52	30.1%	16.4%	66.8%
2006	$56.39	$46.82	$40.70	(6.7%)	(6.5%)	11.4%
2007	$61.83	$55.12	$37.98	9.6%	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	26.1%	16.7%	55.7%
2011	$49.48	$38.72	$37.02	(0.9%)	(4.0%)	24.9%
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%	225.7%
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	$18.81	3.5%	6.7%	9.8%
2018	$39.43	$28.78	$36.82	29.9%	9.6%	95.7%

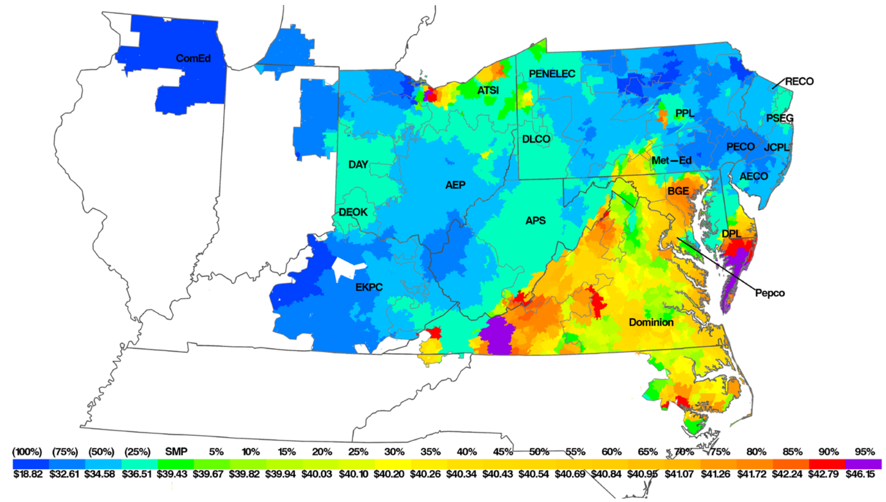
Table 3-73 shows zonal real-time, and real-time, load-weighted, average LMP in the first nine months of 2017 and 2018.

Table 3-73 Zonal real-time and real-time, load-weighted, average LMP (Dollars per MWh): January through September, 2017 and 2018

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2017 (Jan-Sep)	2018 (Jan-Sep)	Percent Change	2017 (Jan-Sep)	2018 (Jan-Sep)	Percent Change
AECO	$26.58	$34.67	30.4%	$28.38	$37.27	31.3%
AEP	$28.89	$36.20	25.3%	$30.15	$38.79	28.7%
APS	$29.12	$38.06	30.7%	$30.56	$41.51	35.8%
ATSI	$29.71	$38.80	30.6%	$31.19	$41.48	33.0%
BGE	$31.64	$42.03	32.8%	$33.73	$46.51	37.9%
ComEd	$26.95	$28.25	4.8%	$28.64	$29.97	4.7%
Day	$29.58	$37.25	25.9%	$31.14	$39.98	28.4%
DEOK	$28.99	$37.55	29.5%	$30.68	$40.56	32.2%
DLCO	$29.03	$38.42	32.3%	$30.58	$41.19	34.7%
Dominion	$30.35	$40.41	33.1%	$32.19	$45.28	40.6%
DPL	$28.06	$38.32	36.6%	$30.36	$44.03	45.0%
EKPC	$27.87	$33.44	20.0%	$29.25	$36.98	26.5%
JCPL	$27.35	$34.91	27.6%	$29.72	$38.10	28.2%
Met-Ed	$28.33	$34.46	21.6%	$30.32	$37.97	25.2%
PECO	$26.70	$34.42	28.9%	$28.42	$37.63	32.4%
PENELEC	$28.10	$36.34	29.3%	$29.28	$38.83	32.6%
Pepco	$30.76	$40.77	32.5%	$32.63	$44.76	37.2%
PPL	$27.15	$33.63	23.9%	$28.85	$37.33	29.4%
PSEG	$27.50	$35.18	27.9%	$29.38	$37.70	28.3%
RECO	$27.69	$35.54	28.3%	$30.02	$38.30	27.6%
PJM	$28.79	$36.52	26.8%	$30.36	$39.43	29.9%

Figure 3-46 is a contour map of the real-time, load-weighted, average LMP in the first nine months of 2018. 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 3-46 Real-time, load-weighted, average LMP: January through September, 2018



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

Figure 3-47 shows the PJM real-time monthly and annual load-weighted LMP for January 1999 through September 2018.

Figure 3-47 Real-time, monthly and annual, load-weighted, average LMP: January 1999 through September 2018

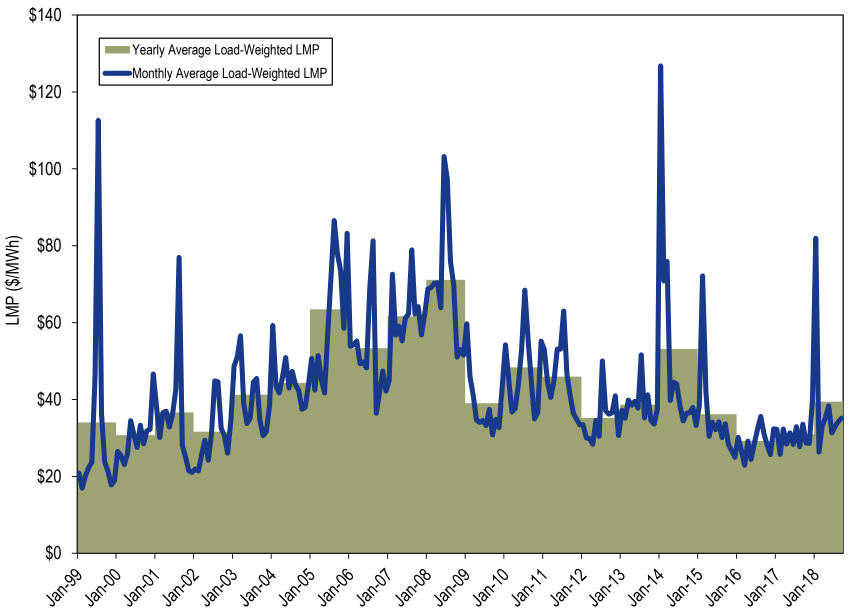
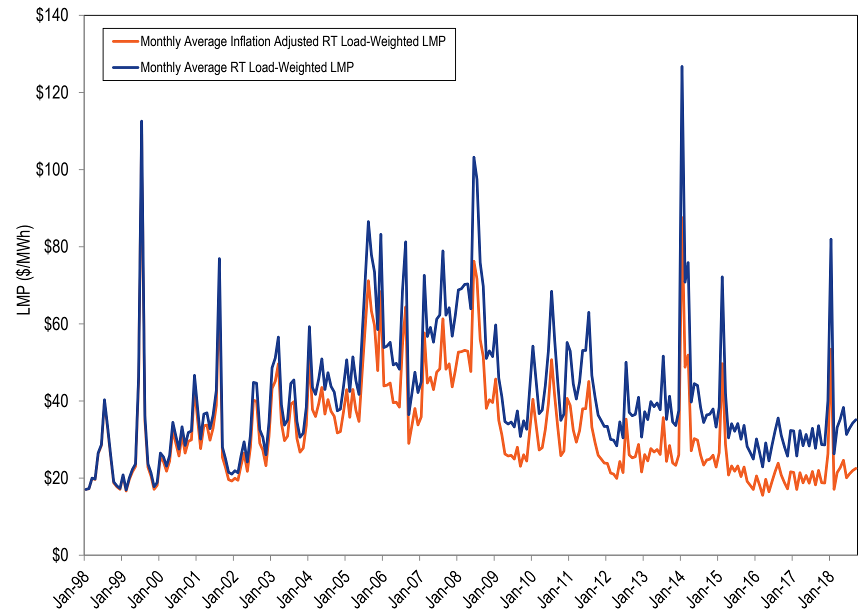


Figure 3-48 Real-time, monthly, load-weighted, average LMP unadjusted and adjusted for inflation: 1998 through 2018



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

Figure 3-48 shows the PJM real-time monthly load-weighted average LMP and inflation adjusted monthly load-weighted average LMP for 1998, through September 2018.[96] Table 3-74 shows the PJM real-time first nine months load-weighted average LMP and inflation adjusted yearly load-weighted average LMP for every year starting from 1998 through 2018.

96 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 19, 2018)

Table 3-74 Real-time, yearly, load-weighted, average LMP unadjusted and adjusted for inflation: January through September, 1998 through 2018

	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
2018	$39.43	$25.45

Fuel Price Trends and LMP

In a competitive market, changes in LMP should follow 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 short run 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. Fuel prices rose in the first nine months of 2018 compared to 2017, but LMPs rose even more. Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. Eastern natural gas prices and coal prices increased in the first nine months of 2018 compared to the first nine months of 2017. The price of Northern Appalachian coal was 7.8 percent higher; the price of Central Appalachian coal was 10.4 percent higher; the price of Powder River Basin coal was 3.8 percent higher; the price of eastern natural gas was 57.7 percent higher; and the price of western natural gas was 0.6 percent lower. Figure 3-49 shows monthly average spot fuel prices.[97]

Figure 3-49 Spot average fuel price comparison with fuel delivery charges: January 2012 through September 2018 ($/MMBtu))

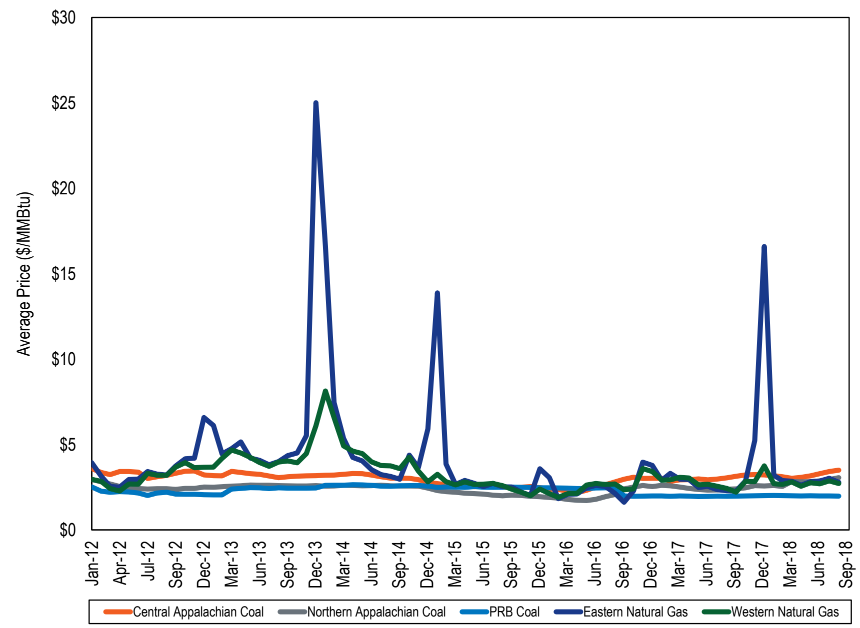


Table 3-75 compares the first nine months of 2018 PJM real-time fuel-cost adjusted, load-weighted, average LMP to the first nine months of 2018 load-weighted, average LMP.[98] The real-time load-weighted average LMP for the first nine months of 2018 increased by $9.08 or 29.9 percent from real-time load-weighted average LMP for the first nine months of 2017. The real-time load-weighted, average LMP for the first nine months of 2018 was 17.7 percent higher than the real-time fuel-cost adjusted, load-weighted, average

97 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.

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

LMP for the first nine months of 2018. The real-time, fuel-cost adjusted, load-weighted, average LMP for the first nine months of 2018 was 10.4 percent higher than the real-time load-weighted LMP for the first nine months of 2017. If fuel and emissions costs in the first nine months of 2018 had been the same as in first nine months of 2017, holding everything else constant, the real-time load-weighted LMP in the first nine months of 2018 would have been lower, $33.51 per MWh, than the observed $39.43 per MWh.

Table 3-75 Real-time, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): January through September, 2017 and 2018

	2018 Fuel-Cost Adjusted, Load-Weighted LMP	2018 Load-Weighted LMP	Change	Percent Change
Average	$33.51	$39.43	$5.92	17.7%
	2017 Load-Weighted LMP	2018 Fuel-Cost Adjusted, Load-Weighted LMP	Change	Percent Change
Average	$30.36	$33.51	$3.15	10.4%
Jan-00	2017 Load-Weighted LMP	2018 Load-Weighted LMP	Change	Change
Average	$30.36	$39.43	$9.08	29.9%

Table 3-76 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 2018. Table 3-76 shows that higher natural gas prices explain most of the fuel-cost related increase in the real-time annual load-weighted average LMP in the first nine months of 2018 from the first nine months of 2017.

Table 3-76 Change in real-time, fuel-cost adjusted, load-weighted average LMP ($/MWh) by fuel type: January through September, 2017 to 2018

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Coal	$1.05	17.7%
Gas	$3.78	63.9%
Municipal Waste	$0.15	2.5%
Oil	$0.94	15.8%
Other	$0.00	0.0%
Uranium	($0.00)	-0.0%
Wind	$0.00	0.0%
Total	$5.92	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 (VOM) 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.[99] 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.[100] 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.

99 New Jersey withdrew from RGGI, effective January 1, 2012 and rejoined RGGI, effective January 29, 2018.
100 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.

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

Table 3-79 shows the frequency and average shadow price of transmission constraints in PJM. In the first nine months of 2018, there were 118,602 transmission constraints in the real-time market with a non-zero shadow price. For nearly 9 percent of these transmission constraints, the line limit was violated, meaning that the flow exceeded the facility limit.[101] In the first nine months of 2018, the average shadow price of transmission constraints when the line limit was violated was nearly seven 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. In the first nine months of 2018, for all the violated transmission constraints for which the penalty factor was greater than or equal to $2,000 per MWh, 59 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 3-77, including markup using unadjusted cost-based offers.[102] Table 3-77 shows that in the first nine months of 2018, 19.8 percent of the load-weighted LMP was the result of coal costs, 39.2 percent was the result of gas costs and 0.61 percent was the result of the cost of emission allowances. Using adjusted cost-based offers, markup was 20.0 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. For several intervals, 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 2018, nearly 23 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 2018 and 2017.

101 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.

102 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 3-77 Components of real-time (Unadjusted), load-weighted, average LMP: January through September, 2017 and 2018

	2017 (Jan - Sep)		2018 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$11.58	38.1%	$15.46	39.2%	1.1%
Coal	$9.20	30.3%	$7.81	19.8%	(10.5%)
Markup	$2.49	8.2%	$5.15	13.1%	4.9%
Ten Percent Adder	$2.33	7.7%	$2.75	7.0%	(0.7%)
NA	$0.88	2.9%	$2.25	5.7%	2.8%
Oil	$0.34	1.1%	$2.22	5.6%	4.5%
VOM	$1.46	4.8%	$1.48	3.7%	(1.1%)
Increase Generation Adder	$0.19	0.6%	$0.89	2.3%	1.7%
LPA Rounding Difference	$1.02	3.4%	$0.64	1.6%	(1.7%)
Ancillary Service Redispatch Cost	$0.25	0.8%	$0.41	1.0%	0.2%
Municipal Waste	$0.05	0.2%	$0.13	0.3%	0.2%
CO_2 Cost	$0.09	0.3%	$0.12	0.3%	(0.0%)
NO_x Cost	$0.51	1.7%	$0.11	0.3%	(1.4%)
Opportunity Cost Adder	$0.00	0.0%	$0.08	0.2%	0.2%
Other	$0.05	0.1%	$0.07	0.2%	0.0%
Scarcity Adder	$0.07	0.2%	$0.03	0.1%	(0.2%)
SO_2 Cost	$0.04	0.1%	$0.01	0.0%	(0.1%)
Market-to-Market Adder	$0.00	0.0%	$0.01	0.0%	0.0%
Constraint Violation Adder	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Uranium	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Wind	($0.15)	(0.5%)	($0.01)	(0.0%)	0.5%
LPA-SCED Differential	($0.01)	(0.0%)	($0.02)	(0.1%)	(0.0%)
Renewable Energy Credits	$0.00	0.0%	($0.04)	(0.1%)	(0.1%)
Decrease Generation Adder	($0.02)	(0.1%)	($0.12)	(0.3%)	(0.2%)
Total	$30.36	100.0%	$39.43	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 3-77 and Table 3-84), markup is simply the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-78 and Table 3-85), the 10 percent markup is removed from the cost-based offers of coal gas and oil units (adjusted markup).

The components of LMP are shown in Table 3-78, including markup using adjusted cost-based offers.

Table 3-78 Components of real-time (Adjusted), load-weighted, average LMP: January through September, 2017 and 2018

	2017 (Jan - Jun)		2018 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$11.58	38.1%	$15.46	39.2%	1.1%
Markup	$4.82	15.9%	$7.88	20.0%	4.1%
Coal	$9.20	30.3%	$7.81	19.8%	(10.5%)
NA	$0.88	2.9%	$2.25	5.7%	2.8%
Oil	$0.34	1.1%	$2.22	5.6%	4.5%
VOM	$1.46	4.8%	$1.48	3.7%	(1.1%)
Increase Generation Adder	$0.19	0.6%	$0.89	2.3%	1.7%
LPA Rounding Difference	$1.02	3.4%	$0.64	1.6%	(1.7%)
Ancillary Service Redispatch Cost	$0.25	0.8%	$0.41	1.0%	0.2%
Municipal Waste	$0.05	0.2%	$0.13	0.3%	0.2%
CO_2 Cost	$0.09	0.3%	$0.12	0.3%	(0.0%)
NO_x Cost	$0.51	1.7%	$0.11	0.3%	(1.4%)
Opportunity Cost Adder	$0.00	0.0%	$0.08	0.2%	0.2%
Other	$0.05	0.1%	$0.07	0.2%	0.0%
Scarcity Adder	$0.07	0.2%	$0.03	0.1%	(0.2%)
Ten Percent Adder	($0.00)	(0.0%)	$0.02	0.1%	0.1%
SO_2 Cost	$0.04	0.1%	$0.01	0.0%	(0.1%)
Market-to-Market Adder	$0.00	0.0%	$0.01	0.0%	0.0%
Constraint Violation Adder	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Uranium	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Wind	($0.15)	(0.5%)	($0.01)	(0.0%)	0.5%
LPA-SCED Differential	($0.01)	(0.0%)	($0.02)	(0.1%)	(0.0%)
Renewable Energy Credits	$0.00	0.0%	($0.04)	(0.1%)	(0.1%)
Decrease Generation Adder	($0.02)	(0.1%)	($0.12)	(0.3%)	(0.2%)
Total	$30.36	100.0%	$39.43	100.0%	0.0%

Table 3-79 Frequency and average shadow price of transmission constraints: January through September, 2017 and 2018

	Frequency		Average Shadow Price	
Description	2017 (Jan - Sep)	2018 (Jan - Sep)	2017 (Jan - Sep)	2018 (Jan - Sep)
PJM Internal Violated Transmission Constraints	8,637	10,539	$651.68	$1,307.70
PJM Internal Binding Transmission Constraints	73,738	71,036	$115.07	$198.67
Market to Market Transmission Constraints	38,354	37,027	$365.06	$424.61
Total	120,729	118,602		

Day-Ahead LMP

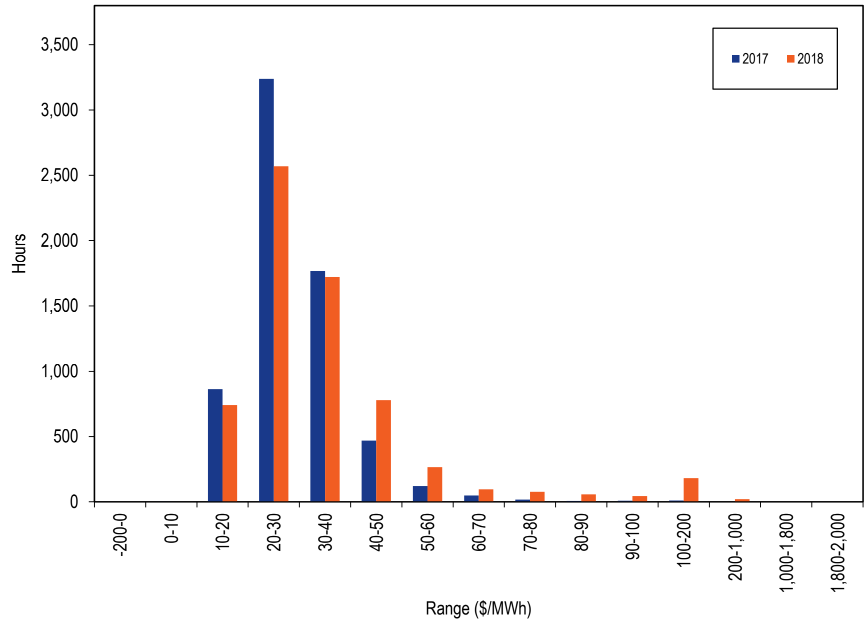
Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[103]

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-50 shows the hourly distribution of PJM day-ahead average LMP in the first nine months of 2017 and 2018.

Figure 3-50 Average LMP for the Day-Ahead Energy Market: January through September, 2017 and 2018



103 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, Average LMP

Table 3-80 shows the PJM day-ahead, average LMP in the first nine months of 2000 through 2018.

Table 3-80 Day-ahead, average LMP (Dollars per MWh): January through September, 2000 through 2018

	Day-Ahead LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	NA	NA	NA	NA	NA	NA
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%	15.3%
2004	$42.64	$42.07	$17.47	3.5%	10.0%	(20.7%)
2005	$54.48	$46.67	$28.83	27.8%	10.9%	65.0%
2006	$50.45	$46.32	$24.93	(7.4%)	(0.7%)	(13.5%)
2007	$54.24	$51.40	$24.95	7.5%	11.0%	0.1%
2008	$71.43	$66.38	$33.11	31.7%	29.1%	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%)	15.8%
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%)
2018	$36.04	$29.75	$25.12	24.7%	11.8%	134.2%

Day-Ahead, Load-Weighted, Average LMP

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

PJM Day-Ahead, Load-Weighted, Average LMP

Table 3-81 shows the PJM day-ahead, load-weighted, average LMP in the first nine months of 2000 through 2018.

Table 3-81 Day-ahead, load-weighted, average LMP (Dollars per MWh): January through September, 2000 through 2018

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	NA	NA	NA	NA	NA	NA
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	31.4%	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%	42.5%
2011	$48.34	$42.35	$26.54	(1.6%)	(2.3%)	24.3%
2012	$34.29	$31.17	$17.17	(29.1%)	(26.4%)	(35.3%)
2013	$39.49	$35.96	$19.90	15.2%	15.4%	15.9%
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%)
2018	$38.71	$31.62	$27.75	27.9%	13.1%	139.5%

Table 3-82 shows zonal day-ahead, and day-ahead, load-weighted, average LMP in the first nine months of 2017 and 2018.

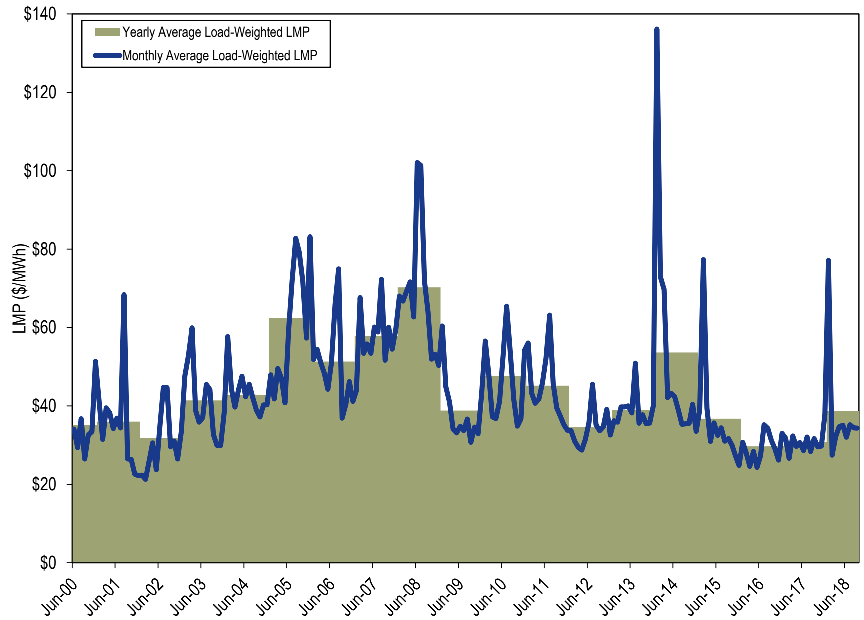
Table 3-82 Zonal day-ahead and day-ahead, load-weighted, average LMP (Dollars per MWh): January through September, 2017 and 2018

	Day-Ahead Average LMP			Day-Ahead, Load-Weighted, Average LMP		
Zone	2017 (Jan-Sep)	2018 (Jan-Sep)	Percent Change	2017 (Jan-Sep)	2018 (Jan-Sep)	Percent Change
AECO	$26.90	$34.66	28.8%	$28.37	$36.95	30.3%
AEP	$29.05	$35.53	22.3%	$30.23	$37.90	25.4%
APS	$29.24	$37.42	28.0%	$30.47	$40.21	32.0%
ATSI	$29.63	$37.35	26.1%	$30.86	$39.53	28.1%
BGE	$31.95	$41.57	30.1%	$33.93	$45.54	34.2%
ComEd	$27.06	$28.06	3.7%	$28.50	$29.80	4.6%
Day	$29.69	$36.90	24.3%	$31.05	$39.43	27.0%
DEOK	$29.16	$38.09	30.6%	$30.70	$41.25	34.4%
DLCO	$29.05	$37.29	28.4%	$30.40	$39.70	30.6%
Dominion	$30.70	$40.18	30.9%	$32.49	$44.78	37.8%
DPL	$28.36	$37.83	33.4%	$30.36	$42.98	41.6%
EKPC	$28.24	$33.14	17.3%	$29.72	$36.25	22.0%
JCPL	$27.59	$34.78	26.1%	$29.29	$37.44	27.8%
Met-Ed	$28.31	$34.67	22.4%	$29.81	$37.51	25.8%
PECO	$26.85	$34.36	27.9%	$28.08	$36.96	31.6%
PENELEC	$28.15	$35.44	25.9%	$29.19	$37.95	30.0%
Pepco	$31.16	$40.44	29.8%	$32.78	$44.15	34.7%
PPL	$27.27	$33.59	23.2%	$28.54	$36.66	28.5%
PSEG	$27.90	$35.47	27.2%	$29.43	$37.97	29.1%
RECO	$28.04	$35.59	26.9%	$29.76	$38.05	27.8%
PJM	$28.90	$36.04	24.7%	$30.26	$38.71	27.9%

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

Figure 3-51 shows the PJM day-ahead, monthly and annual, load-weighted LMP from June 1, 2000 through September 30, 2018.[104]

Figure 3-51 Day-ahead, monthly and annual, load-weighted, average LMP: June 2000 through September 2018



104 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 seven months of that year.

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

Figure 3-54 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 2018.[105] Table 3-83 shows the PJM day-ahead yearly load- weighted average LMP and inflation adjusted first nine months load-weighted average LMP for every year from 2001 through 2018.

Figure 3-52 Day-ahead, monthly, load-weighted, average LMP unadjusted and inflation adjusted: June 2000 through September 2018

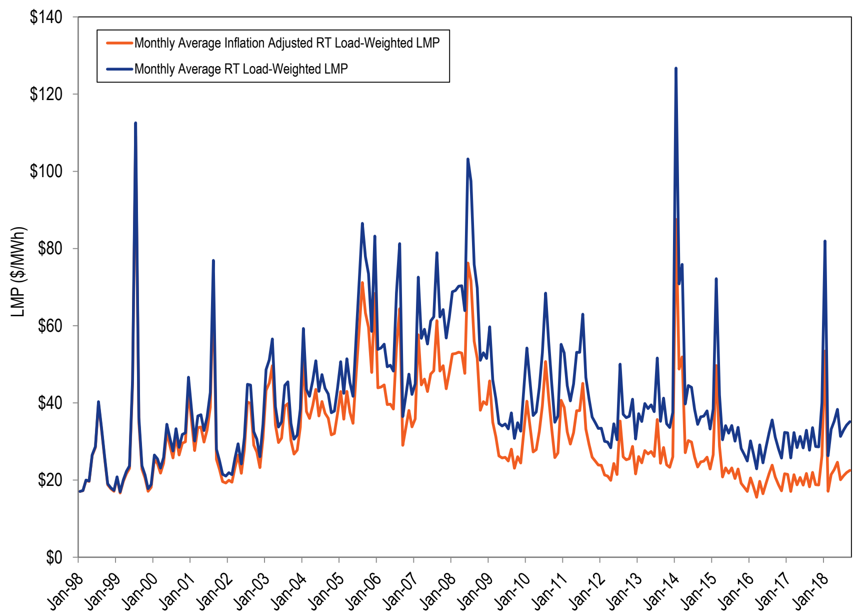


Table 3-83 Day-ahead, yearly, load-weighted, average LMP unadjusted and inflation adjusted: January through September, 2001 through 2018

	Load-Weighted, Average LMP	Inflation Adjusted Load-Weighted, Average LMP
2000	NA	NA
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
2018	$38.71	$24.98

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-based 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

105 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 19, 2018).

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, Maryland and New Jersey.[106] 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 3-84 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In first nine months of 2018, 15.5 percent of the load-weighted LMP was the result of coal costs, 18.6 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, 29.2 percent was the result of DEC bid costs and 18.1 percent was the result of INC bid costs.

Table 3-84 Components of day-ahead, (unadjusted), load-weighted, average LMP (Dollars per MWh): January through September, 2017 and 2018

	2017 (Jan - Sep)		2018 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
DEC	$6.99	23.1%	$11.30	29.2%	6.1%
Gas	$5.49	18.2%	$7.20	18.6%	0.4%
INC	$7.01	23.2%	$7.01	18.1%	(5.0%)
Coal	$6.40	21.2%	$5.99	15.5%	(5.7%)
Ten Percent Cost Adder	$1.32	4.4%	$1.63	4.2%	(0.2%)
VOM	$0.87	2.9%	$1.45	3.7%	0.9%
Oil	$0.01	0.0%	$1.40	3.6%	3.6%
Up to Congestion Transaction	$0.92	3.0%	$1.15	3.0%	(0.1%)
Markup	$0.68	2.2%	$0.67	1.7%	(0.5%)
Dispatchable Transaction	$0.04	0.1%	$0.49	1.3%	1.1%
DASR LOC Adder	$0.08	0.3%	$0.17	0.4%	0.2%
CO_2	$0.06	0.2%	$0.15	0.4%	0.2%
NO_x	$0.34	1.1%	$0.06	0.2%	(1.0%)
Price Sensitive Demand	$0.00	0.0%	$0.06	0.1%	0.1%
Opportunity Cost	$0.00	0.0%	$0.01	0.0%	0.0%
SO_2	$0.03	0.1%	$0.00	0.0%	(0.1%)
Constrained Off	$0.00	0.0%	$0.00	0.0%	0.0%
Uranium	($0.00)	(0.0%)	$0.00	0.0%	0.0%
Other	$0.01	0.0%	($0.00)	(0.0%)	(0.0%)
Wind	($0.01)	(0.0%)	($0.01)	(0.0%)	0.0%
DASR Offer Adder	$0.01	0.0%	($0.03)	(0.1%)	(0.1%)
NA	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Total	$30.26	100.0%	$38.71	100.0%	(0.0%)

106 New Jersey withdrew from RGGI, effective January 1, 2012 and rejoined RGGI, effective January 29, 2018.

Table 3-85 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 3-85 Components of day-ahead, (adjusted), load-weighted, average LMP (Dollars per MWh): January through September, 2017 and 2018

	2017 (Jan - Sep)		2018 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
DEC	$6.99	23.1%	$11.30	29.2%	6.1%
Gas	$5.49	18.2%	$7.20	18.6%	0.4%
INC	$7.01	23.2%	$7.01	18.1%	(5.0%)
Coal	$6.40	21.2%	$5.99	15.5%	(5.7%)
Markup	$1.97	6.5%	$2.27	5.9%	(0.6%)
VOM	$0.87	2.9%	$1.45	3.7%	0.9%
Oil	$0.01	0.0%	$1.40	3.6%	3.6%
Up to Congestion Transaction	$0.92	3.0%	$1.15	3.0%	(0.1%)
Dispatchable Transaction	$0.04	0.1%	$0.49	1.3%	1.1%
DASR LOC Adder	$0.08	0.3%	$0.17	0.4%	0.2%
CO_2	$0.06	0.2%	$0.15	0.4%	0.2%
NO_x	$0.34	1.1%	$0.06	0.2%	(1.0%)
Price Sensitive Demand	$0.00	0.0%	$0.06	0.1%	0.1%
Ten Percent Cost Adder	$0.03	0.1%	$0.03	0.1%	(0.0%)
Opportunity Cost	$0.00	0.0%	$0.01	0.0%	0.0%
SO_2	$0.03	0.1%	$0.00	0.0%	(0.1%)
Constrained Off	$0.00	0.0%	$0.00	0.0%	0.0%
Uranium	($0.00)	(0.0%)	$0.00	0.0%	0.0%
Other	$0.01	0.0%	($0.00)	(0.0%)	(0.0%)
Wind	($0.01)	(0.0%)	($0.01)	(0.0%)	0.0%
DASR Offer Adder	$0.01	0.0%	($0.03)	(0.1%)	(0.1%)
NA	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Total	$30.26	100.0%	$38.71	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 3-86 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 2017 and 2018. In the first nine months of 2018, 49.9 percent of all cleared UTC transactions were net profitable. Of cleared UTC transactions, 63.7 percent were profitable on the source side and 37.0 were profitable on the sink side but only 5.7 percent were profitable on both the source and sink side.

Table 3-86 Cleared UTC profitability by source and sink point: January through September, 2017 and 2018[107]

Jan-Sep	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	UTC Profitable at Source and Sink	Profitable UTC	Profitable Source	Profitable Sink	Profitable at Source and Sink
2017	14,623,771	7,841,601	9,254,364	5,483,049	722,178	53.6%	63.3%	37.5%	4.9%
2018	7,480,780	3,730,433	4,763,121	2,768,109	422,976	49.9%	63.7%	37.0%	5.7%

Table 3-87 shows the number of cleared INC and DEC transactions, the number of profitable cleared transactions in the first nine months of 2017 and 2018. Of cleared INC and DEC transactions in the first nine months of 2018, 65.5 percent of INCs were profitable and 38.3 percent of DECs were profitable.

Table 3-87 Cleared INC and DEC profitability: January through September, 2017 and 2018

Jan-Sep	Cleared INC	Profitable INC	Profitable INC	Cleared DEC	Profitable DEC	Profitable DEC
2017	1,627,617	1,047,504	64.4%	1,051,193	428,595	64.4%
2018	1,549,323	1,015,566	65.5%	1,182,673	452,564	38.3%

107 Calculations exclude PJM administrative charges.

Figure 3-53 shows total UTC daily gross profits and losses and net profits and losses in the first nine months of 2018.

Figure 3-53 UTC daily gross profits and losses and net profits: January through September, 2018[108]

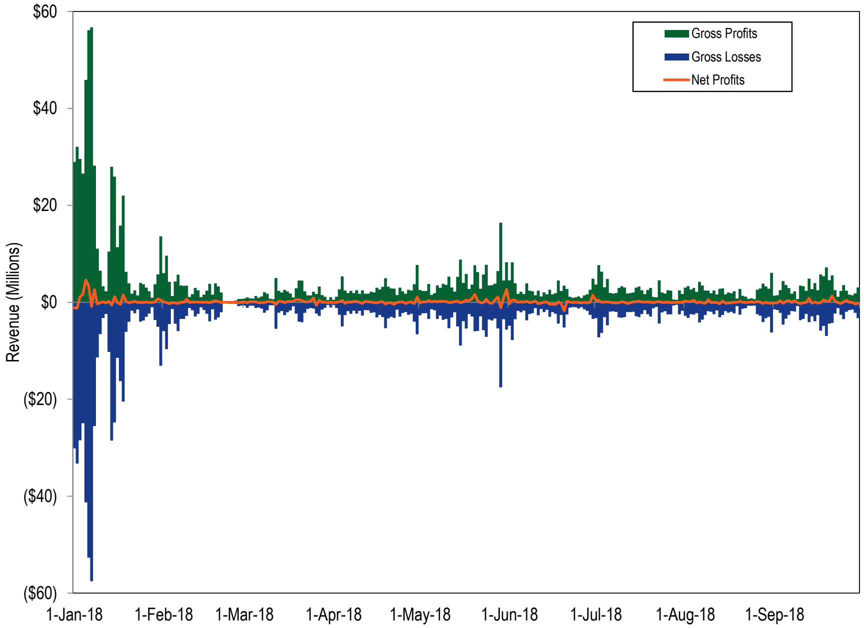
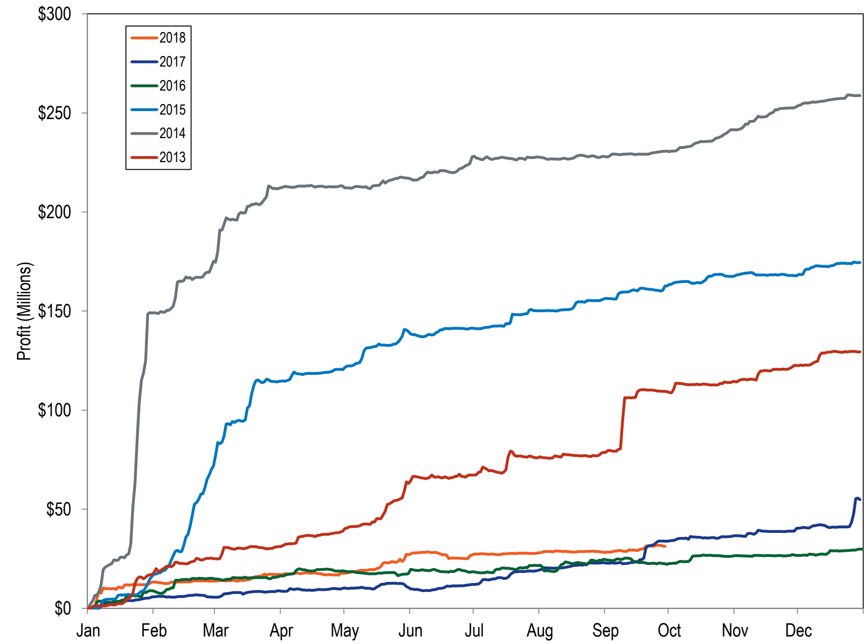


Figure 3-54 shows the cumulative UTC daily profits for January 1, 2013 through September 30, 2018. UTC profits during this period were primarily a result of significant unanticipated price differences between day ahead and real time LMPs. The large increases in cumulative daily UTC profits were due to 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 and December 2017 as a result of profits from the significant day-ahead and real-time price difference that resulted from the shortage event on September 21, 2017 and cold weather in late December. Cumulative daily UTC profits increased significantly during the cold weather in January 2018 as a result of large day ahead and real-time price differences.

Figure 3-54 Cumulative daily UTC profits: January 2013 through September 2018



108 Calculations exclude PJM administrative charges.

Table 3-88 shows UTC profits by month for January 1, 2013 through September 30, 2018. May 2016, September 2016, February 2017 and June 2018 were the only months in the past six years where the total monthly profits were negative.

Table 3-88 UTC profits by month: January 2013 through September 2018

	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)	$3,083,167	$944,939	$1,245,988	$868,400	$7,053,390	$4,002,063	$10,960,012	$2,360,817	$2,716,950	$15,936,217	$54,870,839
2018	$13,184,346	$506,509	$3,410,577	$688,796	$9,499,735	($768,614)	$1,163,380	$692,736	$2,845,649				$31,223,113

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 3-56).

Table 3-89 shows that the difference between the average real-time price and the average day-ahead price was -$0.11 per MWh in the first nine months of 2017, and $0.48 per MWh in the first nine months of 2018. The difference between average peak real-time price and the average peak day-ahead price was -$0.11 per MWh in the first nine months of 2017 and -$0.20 per MWh in the first nine months of 2018.

Table 3-89 Day-ahead and real-time average LMP (Dollars per MWh): January through September, 2017 and 2018[109]

	2017 (Jan-Sep)				2018 (Jan-Sep)			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$28.90	$28.79	($0.11)	(0.4%)	$36.04	$36.52	$0.48	1.3%
Median	$26.60	$25.28	($1.31)	(5.2%)	$29.75	$27.26	($2.48)	(9.1%)
Standard deviation	$10.73	$16.81	$6.08	36.2%	$25.12	$33.22	$8.10	24.4%
Peak average	$34.01	$33.90	($0.11)	(0.3%)	$41.90	$41.70	($0.20)	(0.5%)
Peak median	$32.00	$29.37	($2.63)	(9.0%)	$35.92	$32.30	($3.62)	(11.2%)
Peak standard deviation	$11.67	$20.89	$9.22	44.1%	$25.56	$31.13	$5.57	17.9%
Off peak average	$24.43	$24.32	($0.11)	(0.4%)	$30.91	$31.98	$1.07	3.3%
Off peak median	$22.75	$22.40	($0.36)	(1.6%)	$24.37	$23.44	($0.93)	(4.0%)
Off peak standard deviation	$7.34	$10.27	$2.93	28.6%	$23.57	$34.31	$10.74	31.3%

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

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 3-90 shows the difference between the real-time and the day-ahead energy market prices for the first nine months of 2001 through 2018.

Table 3-90 Day-ahead and real-time average LMP (Dollars per MWh): January through September, 2001 through 2018

(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	($0.78)	(1.9%)
2004	$42.64	$43.85	$1.21	2.8%
2005	$54.48	$54.69	$0.21	0.4%
2006	$50.45	$51.79	$1.34	2.6%
2007	$54.24	$57.34	$3.10	5.4%
2008	$71.43	$71.94	$0.51	0.7%
2009	$37.35	$37.42	$0.07	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)	(2.0%)
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%)
2018	$36.04	$36.52	$0.48	1.3%

Table 3-91 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for January through September, 2017 and 2018.

Table 3-91 Frequency distribution by hours of real-time LMP minus day-ahead LMP (Dollars per MWh): January through September, 2017 and 2018

	2017 (Jan-Sep)		2018 (Jan-Sep)	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%
($1,000) to ($750)	0	0.00%	0	0.00%
($750) to ($500)	0	0.00%	0	0.00%
($500) to ($450)	0	0.00%	0	0.00%
($450) to ($400)	0	0.00%	0	0.00%
($400) to ($350)	0	0.00%	0	0.00%
($350) to ($300)	0	0.00%	0	0.00%
($300) to ($250)	0	0.00%	0	0.00%
($250) to ($200)	0	0.00%	0	0.00%
($200) to ($150)	0	0.00%	1	0.02%
($150) to ($100)	2	0.03%	3	0.06%
($100) to ($50)	3	0.08%	31	0.53%
($50) to $0	4,098	62.63%	4,130	63.58%
$0 to $50	2,414	99.48%	2,244	97.83%
$50 to $100	26	99.88%	102	99.39%
$100 to $150	5	99.95%	24	99.76%
$150 to $200	1	99.97%	5	99.83%
$200 to $250	0	99.97%	8	99.95%
$250 to $300	0	99.97%	1	99.97%
$300 to $350	0	99.97%	1	99.98%
$350 to $400	0	99.97%	0	99.98%
$400 to $450	1	99.98%	1	100.00%
$450 to $500	0	99.98%	0	100.00%
$500 to $750	1	100.00%	0	100.00%
$750 to $1,000	0	100.00%	0	100.00%
$1,000 to $1,250	0	100.00%	0	100.00%
>= $1,250	0	100.00%	0	100.00%

Figure 3-55 shows the hourly differences between day-ahead and real-time hourly LMP in the first nine months of 2018.

Figure 3-55 Real-time hourly LMP minus day-ahead hourly LMP: January through September, 2018

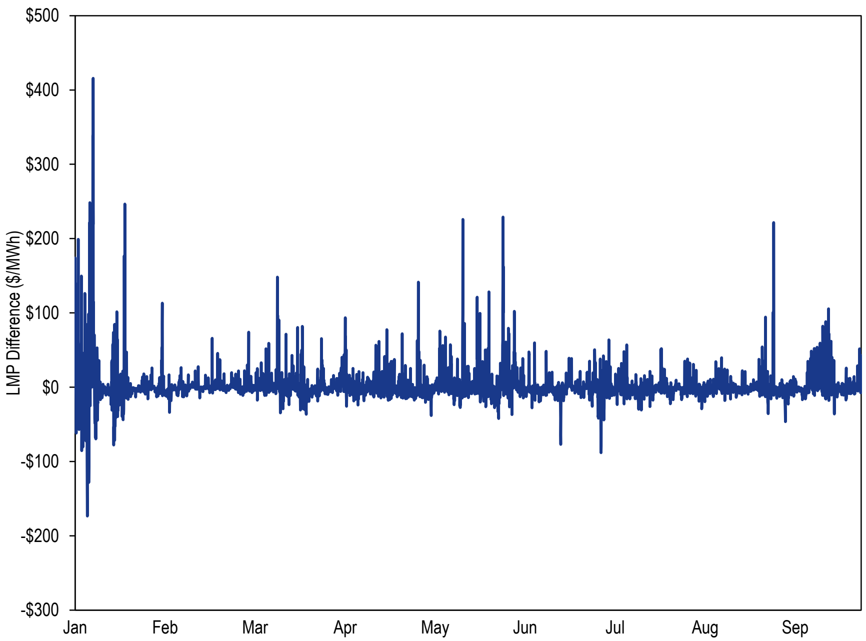


Figure 3-56 shows the monthly average of the differences between the day-ahead and real-time PJM average LMPs from January 1, 2013, through September 30, 2018.

Figure 3-56 Monthly average of real-time minus day-ahead LMP: January 2013 through September 2018

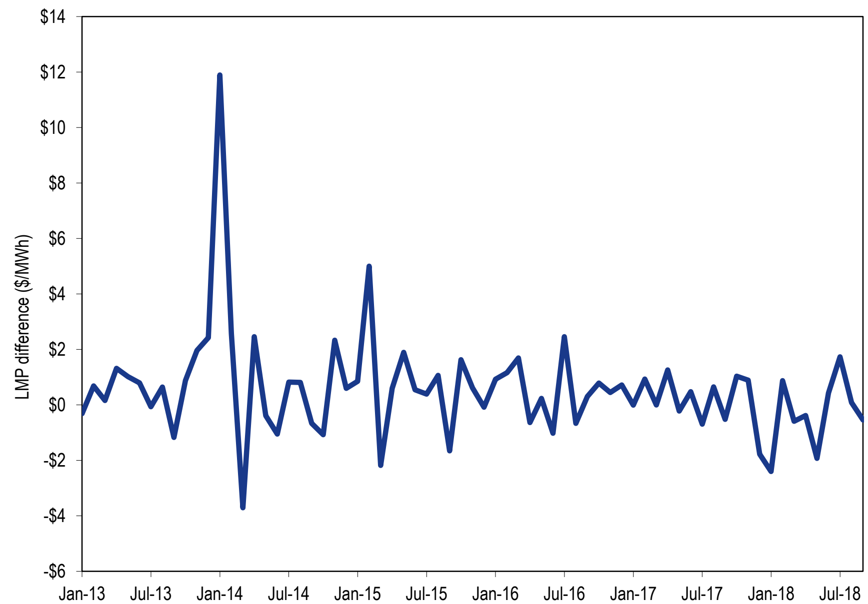


Figure 3-57 shows the monthly average of the absolute value of the differences between the day-ahead and real-time hourly, nodal LMPs from January 1, 2013, through September 30, 2018.

Figure 3-57 Monthly average of absolute value of real-time minus day-ahead LMP by pnode: January 2013 through September 2018

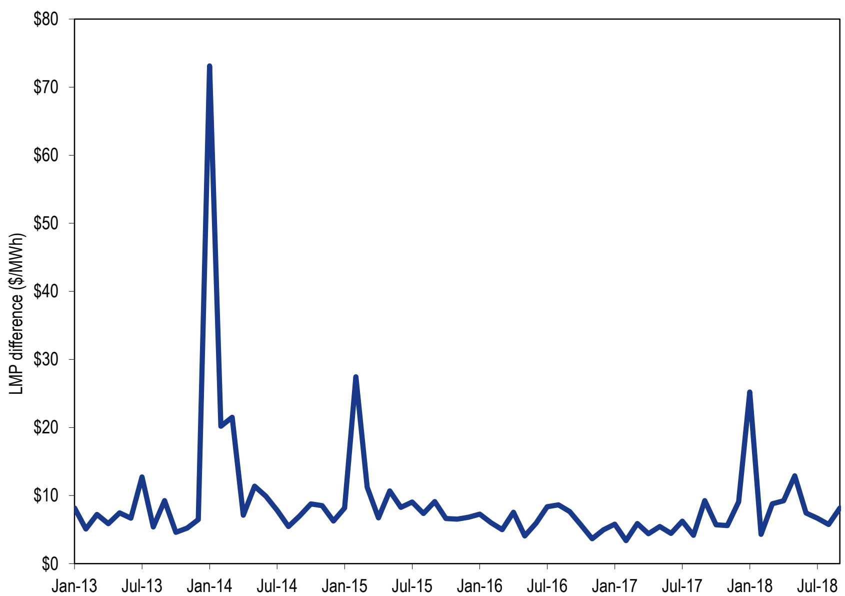
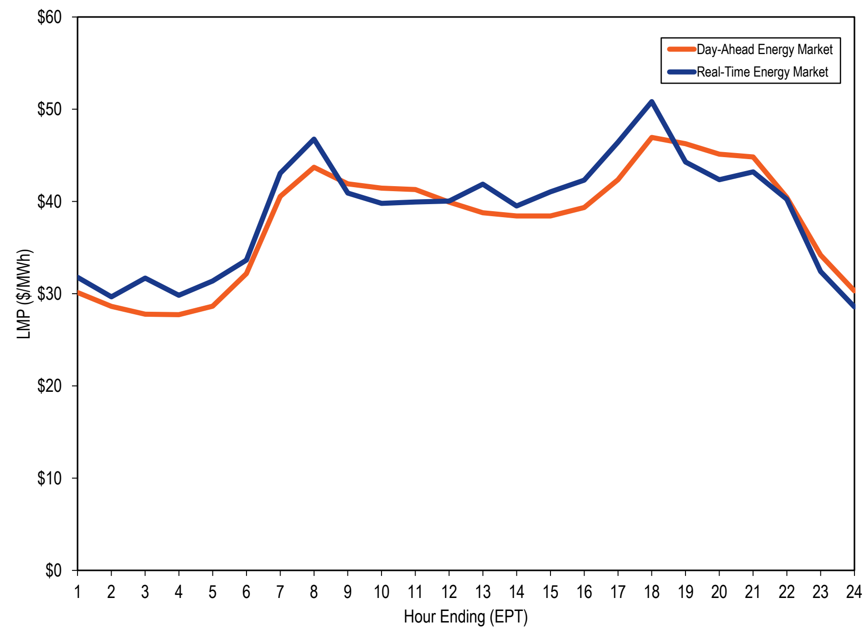


Figure 3-58 shows day-ahead and real-time LMP on an average hourly basis for the first nine months of 2018. Hour ending 17 had the largest difference between the DA and RT LMP, at $1.86 per MWh, and hour ending 12 had the smallest difference at $0.09 per MWh. The average for the first nine months of 2018 was $0.48 per MWh higher in the RT LMP than DA LMP.

Figure 3-58 System hourly average LMP: January through September, 2018



Scarcity

PJM's energy market did not experience any shortage pricing events in the first nine months of 2018. Table 3-92 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in the first nine months of 2017 and 2018.

Table 3-92 Summary of emergency events declared: January through September, 2017 and 2018

	Number of days events declared	
Event Type	Jan - Sep, 2017	Jan - Sep, 2018
Cold Weather Alert	0	12
Hot Weather Alert	17	23
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	1	0
Energy export recalls from PJM capacity resources	0	0

Figure 3-59 shows the number of days that weather and capacity emergency alerts were issued in PJM in the first nine months from 2014 through 2018. Figure 3-60 shows the number of days emergency warnings were issued and actions were taken in PJM in the first nine months from 2014 through 2018.

Figure 3-59 Declared emergency alerts: January through September, 2014 through 2018

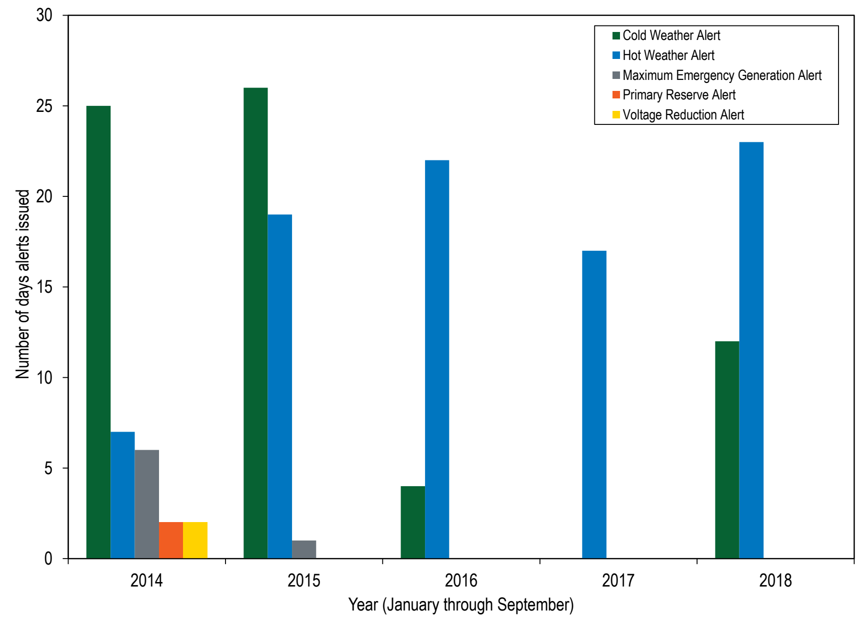
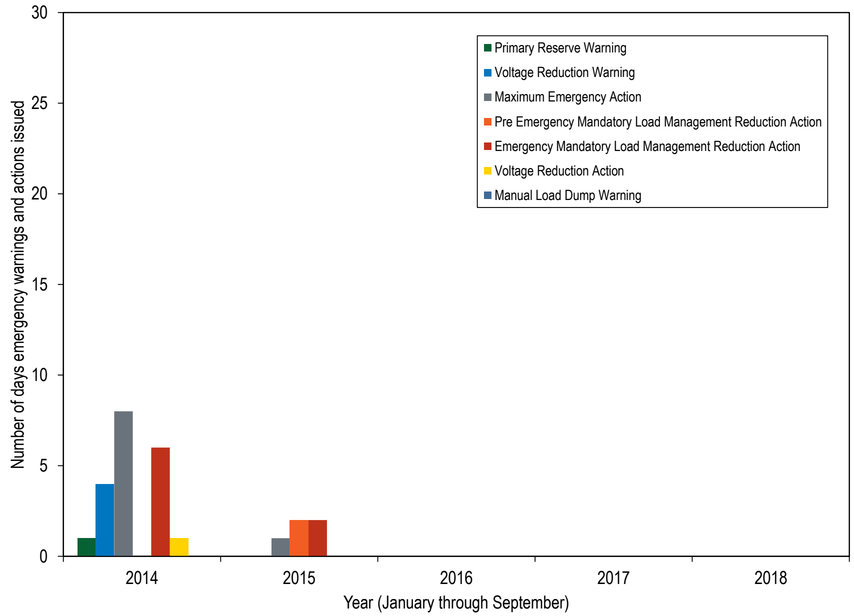


Figure 3-60 Declared emergency warnings and actions: January through September, 2014 through 2018



Emergency Procedures

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

PJM declared cold weather alerts on 12 days in the first nine months of 2018 compared to zero days in the first nine months of 2017.[110] 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 or fall below 10 degrees Fahrenheit.

110 See PJM. "Manual 13: Emergency Operations," Rev. 65 (Jan. 1, 2018), Section 3.3 Cold Weather Alert, p. 56.

PJM declared hot weather alerts on 23 days in the first nine months of 2018 compared to 17 days in the first nine months of 2017.[111] 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 2018 and 2017. 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.[112] 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 2018 and 2017. 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.[113] It is issued when the estimated primary reserves are less than the forecast primary reserve requirement.

PJM did not declare any voltage reduction alerts in the first nine months of 2018 and 2017. 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.[114] 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 2018 and 2017. 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.[115]

111 See PJM. "Manual 13: Emergency Operations," Rev. 65 (Jan. 1, 2018), Section 3.4 Hot Weather Alert, p. 60.
112 See PJM. "Manual 13: Emergency Operations," Rev. 65 (Jan. 1, 2018), Section 2.3.1 Advance Notice Emergency Procedures: Alerts, p. 23.
113 *Id* at 24.
114 *Id* at 25.
115 *Id* at 33.

PJM did not declare any voltage reduction warnings or reductions of noncritical plant load in the first nine months of 2018 and 2017. 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 2018 and 2017. 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.[116]

PJM did not declare any maximum emergency generation actions in the first nine months of 2018 and 2017. 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.[117] 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 2018 and 2017.

PJM did not declare any voltage reduction actions in the first nine months of 2018 and 2017. 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 17 synchronized reserve events in the first nine months of 2018 compared to 16 events in the first nine months of 2017.[118] Synchronized reserve events may occur at any time of the year due to sudden loss of generation or transmission facilities, or sudden loss of imports, and do not necessarily coincide with capacity emergency conditions such as maximum generation emergency events or emergency load management events.

Table 3-93 provides a description of PJM declared emergency procedures.

116 See PJM. "Manual 13: Emergency Operations," Rev. 65 (Jan. 1, 2018), Section 2.3 Capacity Shortages, at 30–32.
117 *Id* at 34.

118 See *2018 Quarterly State of the Market Report for PJM: January through September*, Section 10: Ancillary Service Markets for details on the spinning events.

Table 3-93 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 3-94 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in the first nine months of 2018.

Table 3-94 Declared emergency alerts, warnings and actions: January through September, 2018

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	Manual Load Dump Action	Load Shed Directive
1/1/2018	PJM RTO													
1/2/2018	PJM RTO													
1/3/2018	Western													
1/4/2018	Western													
1/5/2018	PJM RTO													
1/6/2018	PJM RTO													
1/7/2018	PJM RTO													
1/14/2018	Western													
1/16/2018	Western													
1/17/2018	Western													
2/5/2018	ComEd													
2/6/2018	ComEd													
5/3/2018		Mid Atlantic and Dominion												
5/4/2018		Mid Atlantic and Dominion												
5/28/2018		Western												
5/29/2018		Mid Atlantic and Western												AEP (Edison Area)
6/1/2018		Mid Atlantic and Dominion												
6/17/2018		Western												
6/18/2018		PJM RTO												
6/29/2018		PJM RTO												
6/30/2018		PJM RTO												
7/1/2018		PJM RTO												
7/2/2018		Mid Atlantic and Dominion												
7/3/2018		Mid Atlantic and Dominion												
7/10/2018		Mid Atlantic and Dominion												
7/14/2018		Mid Atlantic region, AEP, Dayton, DEOK, EKPC, APS, and ATSI zones												
7/15/2018		Mid Atlantic region, AEP, DEOK, Dominion and EKPC zones												
7/16/2018		Mid Atlantic and Dominion												
7/18/2018														AEP (Lonesone Pine area)
8/27/2018		Mid Atlantic Region, Dominion and ComEd zones												
8/28/2018		Mid Atlantic and Dominion												
8/29/2018		Mid Atlantic and Dominion												
8/30/2018		Dominion												
9/4/2018		PJM RTO												
9/5/2018		PJM RTO												
9/6/2018		Mid Atlantic and Dominion												

AEP Twin Branch Load Shed Event

On May 29, 2018, at 1322 EPT, PJM directed AEP, the local transmission owner, to shed 21 MW of load in the Edison area in northern Indiana to prevent a post contingency cascade condition. This action triggered a Performance Assessment Interval (PAI). The sequence of events that led to the load shed event point to important market design and operational issues including the lack of nodal dispatch for demand resources, and the inability to reflect the lack of supply resources in LMPs. The event also highlighted the importance for multiple contingency analyses in local areas where multiple planned outages, and simultaneous unplanned outages, can result in potential reliability issues.

On May 28, 2018, PJM issued a hot weather alert for the operating day of May 29, 2018 for the Mid-Atlantic and Western regions of PJM. There were three lines in the area that were out of service on planned outages on May 29, 2018.[119] PJM's (n-1) contingency analyses indicated no reliability concerns in the area and PJM did not initially recall these outages. At 1236 EPT, the Twin Branch – Jackson Road 138 kV Line and the Jackson Road 345/138 kV Transformer 3 tripped. At 1248 EPT, PJM operators identified contingency overloads on the Edison- Kankakee Line for two potential contingency scenarios. The first was due to the potential loss of the Twin Branch 6 and 7 transformers (modeled as a single contingency) and the second was due to the potential loss of the Twin Branch – South Bend 138 kV Line. At 1312 EPT, the second contingency scenario, with the potential loss of the Twin Branch – South Bend 138 kV Line, did not solve and indicated a potential cascade condition. At 1322 EPT, PJM directed AEP to shed load in the Edison area to reduce post contingency flows on the Edison – Kankakee line for the potential loss of the Twin Branch – South Bend 138 kV line. At 1337 EPT, the Jackson Road 345/138 kV Transformer was restored, and at 1346, PJM canceled the load shed.

The load shed directive issued at 1322 EPT triggered a Performance Assessment Interval for the Edison area, under Capacity Performance rules, and was in effect until 1346 EPT, when PJM canceled the load shed directive. There were no generation resources in the area that could have provided relief to the post contingency flows on the Edison-Kankakee line. PJM operators could not dispatch any potential demand resources (DR) in the area because PJM has limited visibility of DR at the nodal level, and cannot dispatch DR at a level more granular than a zone unless the area is predefined as a DR subzone. In this instance, there were no subzones defined as DR subzones in the Edison area. This prevented PJM operators from potentially dispatching demand resources during the emergency event. If PJM were to call on demand resources for the entire AEP zone, under Capacity Performance rules, it would have triggered a Performance Assessment Interval in the entire AEP zone, which would not have reflected the local reliability issue in the Edison area, and would have caused generation resources outside the Edison area to produce more energy than needed. This event illustrates the inconsistency of treating capacity resources differently that are treated in the capacity market as full substitutes for other capacity resources and that receive the same capacity revenues but have different obligations to perform in the energy market. The MMU recommends that demand resources be modeled nodally and be required to be nodally dispatchable, similar to generation resources.

The Twin Branch event points to the implications of not having locational scarcity pricing. PJM did not have any additional supply in the Edison area to provide relief to the Edison – Kankakee line, and subsequently had to shed load for reliability, but the LMPs in the area did not reflect the local supply and demand conditions. In instances where there are multiple planned outages or reliability concerns, PJM should determine whether to model constraints in the energy market that reflect (n-2) or (n-3) contingency flow limits. In the absence of supply or demand resources to solve for the (n-2) or (n-3) contingency flow limits, the transmission limit penalty factor associated with those constraints would have set prices in the Edison area.

When transmission outage requests are received, PJM analyzes the reliability conditions due to outages before approving them. In this instance, PJM analyzed the system in the area and found no issues with (n-1) contingency analysis with the three planned outages. However, the unplanned outages of

119 *See* PJM, "Twin Branch / Edison Area Load Shed Event May 29, 2018", Presented to the System Operations Subcommittee (July 5, 2018) <http://www.pjm.com/-/media/committees-groups/subcommittees/sos/20180705/20180705-item-04-twin-branch-area-load-shed.ashx>.

the Twin Branch – Jackson Road 138 kV Line and the Jackson Road 345/138 kV Transformer 3, in combination with the three planned line outages, indicated a potential for a cascade condition from the potential loss of one more facility. PJM should explore conducting reliability analyses in local areas with multiple simultaneous planned outages that go beyond an (n-1) contingency study to account for issues that may arise due to simultaneous unplanned outages.

AEP Lonesome Pine Load Shed Event

On July 18, 2018, at 1052 EPT, PJM directed AEP, the local transmission owner, to shed load in the Lonesome Pine - Bluefield area in Virginia and West Virginia to return voltages from below load dump levels to acceptable levels. This action triggered a Performance Assessment Interval (PAI) from 1114 EPT, when AEP shed load, to 1237 EPT when the load was restored. AEP shed 32 MW of load during this period that affected customers in Virginia and West Virginia. There were no generation resources in the area that could have provided the needed local voltage support.

The low voltage resulted from a combination of a scheduled transmission facility outage that started on July 16, 2018 (Buckhorn – Lonesome Pine 138 kV line) and an unplanned trip of the Glen Lyn 138 kV bus on July 18, 2018 at 0937 EPT. This resulted in a radial load pocket in the Lonesome Pine area. The trip of the Glen Lyn 138 kV bus resulted in automatic switching in service of a capacitor at South Bluefield that led to a voltage spike that resulted in a trip of that capacitor and another capacitor at South Princeton at 1052 EPT. This led to the voltage levels in the Lonesome Pine area to fall 5 kV below the load dump level. PJM issued the load shed directive to AEP to return the voltage to acceptable levels. AEP shed load at 1114 EPT. At 1237 EPT, the South Princeton capacitor was restored increasing voltages to levels above the load dump rating and the load shed was terminated.

There were demand response resources in the area with base capacity commitment totaling less than 1 MW. The demand response resources were part of the load that was shed by AEP during the event. The settlement treatment of these resources has not yet been finalized.

The Lonesome Pine event, similar to the Twin Branch load shed event, points to the implications of not having locational scarcity pricing. PJM did not have any additional supply to provide voltage support in the Bluefield and Lonesome Pine area, and subsequently had to shed load for reliability, but the LMPs in the area did not reflect the local supply and demand conditions. The Glen Lyn 138 kV bus tripped at 0937 EPT, that created the radial load pocket, the South Bluefield and South Princeton capacitors tripped at 1052 and load was shed between 1114 EPT and 1237 EPT. There was no mechanism to reflect the system conditions in prices during the entire progression of events.

PAIs and Capacity Performance

Both the Twin Branch and Lonesome Pine events triggered Performance Assessment Intervals (PAIs) in very limited locations. Both the events occurred due to the simultaneous planned outages and unplanned outages of transmission facilities including transmission lines, transformers and capacitors. While these events involved shedding load to ensure the contingencies did not have cascading effects on the grid, they are not directly related to capacity shortages to meet load at the zonal, regional or the RTO level. PJM determined that there were no generation or demand resources in either case that could have helped resolve the contingency flow or low voltage issues identified during these events. PJM did not assess nonperformance charges to any resources for these events.

The balancing ratio is theoretically defined as the ratio of actual load and reserve requirements during an emergency event in an area to the total committed capacity in the area. In the case of both these events, if the area is defined as the location where the load was shed, the balancing ratio is undefined because there were no committed resources in the area, other than less than 1.0 MW of demand response. It would not be appropriate or correct to calculate a balancing ratio as a measure of capacity needed during these events by defining a wider area to include committed capacity. It is also not appropriate to use a balancing ratio defined in that way in defining the capacity market offer cap. These events occurred in a very small local area where no capacity resources were held to CP performance requirements. Assessing nonperformance to resources located in the wider area would not be appropriate because their performance would not have helped, and may have even exacerbated the transmission issues identified during these events. These events also do not reflect the type of events that are modeled to define the target installed reserve margin in the capacity market. The MMU recommends that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs) in the calculation of the capacity market default offer cap, and only include those events that trigger emergencies at a defined sub-zonal or zonal level.

Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, including reserve requirements, is nearing the limits of the currently 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. PJM refers to scarcity pricing as shortage pricing. The terms are used interchangeably here.

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.[120] 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 reserve penalty factors are incorporated in the calculation of the market clearing prices for the reserve that is short. 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 is only 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.[121] When there are no emergency conditions in place, the ORDC remains 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 2018, there were no shortage pricing events in PJM.

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").[122] In particular, the price formation NOPR proposed (i) to require the alignment of settlement and

120 See OA Schedule 1 § 2.2(d).

121 151 FERC ¶ 61,017 (2015).

122 152 FERC ¶ 61,218 (2015).

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.[123]

The Commission 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.[124] As of May 11, 2017, the rule requires PJM to trigger shortage pricing for any five minute interval for which the Real-Time SCED (Security Constrained Economic Dispatch) indicates a shortage of synchronized reserves or primary reserves. Prior to May 11, 2017, if 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 was considered a transient shortage, a shortage event was not declared, and shortage pricing was not implemented. Both Real-Time SCED and Intermediate-Term SCED had to consistently identify that a shortage of a particular reserve product existed 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 indicated a shortage of RTO wide primary reserve for an interval but the Intermediate-Term SCED forecasts that the reserve shortage did not extend beyond its first look ahead interval (15 minutes ahead of the Real-Time SCED Interval), it was considered a transient shortage, and shortage pricing was not implemented. If Real-Time SCED indicated a shortage of RTO wide primary reserve for an interval and the Intermediate-Term SCED forecasts that the reserve shortage extended for at least two look ahead intervals (30 minutes ahead of the Real-Time SCED Interval), shortage pricing was 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.[125]

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.[126] 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.[127] 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.[128]

On May 11, 2017, PJM implemented five minute shortage pricing. From May 11 through December 31, 2017, there were 21 intervals when five minute shortage pricing was triggered, all on the same day, September 21, 2017.

123 *Id* at P 5.
124 *Id* at P 162.

125 *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).
126 *See PJM Interconnection LLC*, Order No. 825 Compliance Filing, Docket No. ER17-775 (January 11, 2017) ("January 11th Compliance Filing").
127 Comments of the Independent Market Monitor for PJM, Docket No. ER17-775.
128 *Id.*

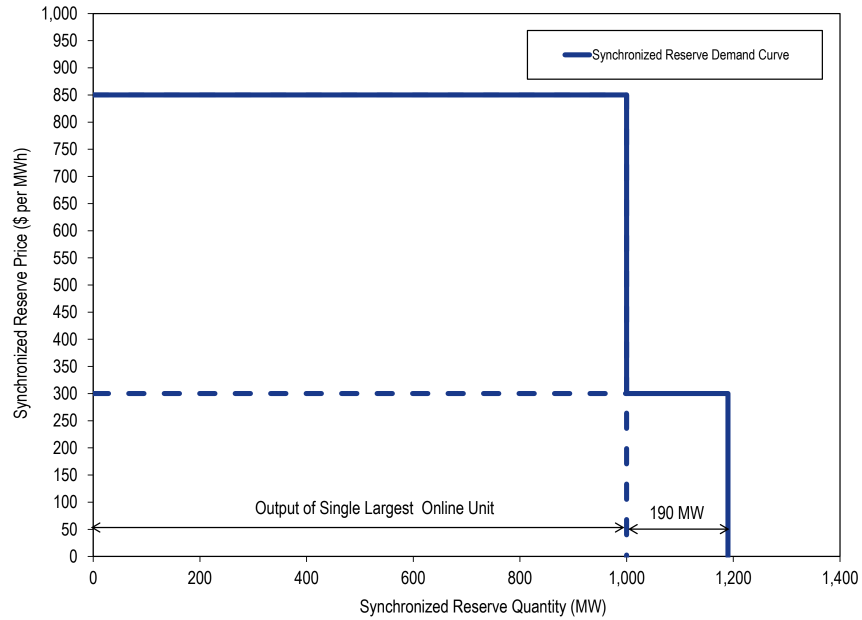
PJM Tariff Revisions to Operating Reserve Demand Curves

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.[129] 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 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 3-61 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.

129 See PJM Filing, FERC Docket No. ER17-1590-000 (May 12, 2017).

Figure 3-61 Updated synchronized reserve demand curve showing the permanent second step



Scarcity Pricing and Energy Price Formation

The current operating reserve demand curves (ORDC) in PJM value the estimated reserves (primary and synchronized reserves) up to the extended reserve requirement quantities. The demand curve shown in Figure 3-61 drops to a zero price for quantities above the extended reserve requirement. The price for reserve quantities less than the reserve requirement is $850 per MWh and the price for reserve quantities above the reserve requirement to 190 MW above the reserve requirement is $300 per MWh. The price below the reserve requirement should be sufficient to cover the marginal cost of any generator on the system capable of responding. The price for carrying reserves in excess of the requirement serves a different function, to economically procure additional reserves.

Unlike an energy only market, PJM does not set scarcity prices to compensate the full fixed and avoidable cost of the resources needed to meet peak demand. The PJM market compensates resources with a capacity market obligation for availability to the system any time they are needed to meet demand. In addition, because consumers do not respond in the short run to real-time energy market prices, scarcity pricing cannot ration scarce energy among consumers according to their marginal willingness to pay. By extension, PJM cannot measure consumers' willingness to pay for reserves to avoid a loss of load. Therefore, the ORDC appropriately does not attempt to administratively represent consumers' willingness to pay for reserves, or customers' value of lost load.

Locational Reserve Requirements

In addition to the construction of the operating reserve demand curves to reflect the value of maintaining reserves and avoiding a loss of load event, the modeling of reserve requirements should reflect locational needs and should price operator actions, for example, to commit more reserves than required.

The current operating reserve demand curves are modeled for reserve requirements for the RTO level (RTO reserve zone) and for the Mid-Atlantic and Dominion region (MAD Subzone). This was a result of historical congestion patterns where limits to transmission capacity to deliver power from outside the MAD Subzone into the MAD Subzone necessitated maintaining reserves in the MAD area to respond to disturbances within the subzone. However, in real-time operations, due to generator outages, transmission outages, and local weather patterns, PJM may need to maintain or operate resources in local areas to maintain local reliability, in addition to the RTO and MAD reserve levels. Currently, these units are committed out of market for reliability reasons, or are modeled as artificial closed loop interfaces with limited deliverability modeled inside the closed loop from resources located outside. The value of operating these resources, including generators that are manually committed for reliability and demand resources that may be dispatched inside a closed loop, is not reflected in prices. A more efficient way to reflect these requirements would be to have locational reserve requirements that are adjusted based on PJM forecasts and reliability studies.

Operator Actions

Actions taken by PJM operators to maintain reliability, such as committing more reserves than required, may suppress reserves prices. The need to commit more reserves could instead be reflected in the ORDC, allowing the market to efficiently account for the reliability commitment in the energy and reserves markets.

Accuracy of Reserve Measurement

The definition of a shortage of synchronized and primary reserves is based on the measured and estimated levels of load, generation, interchange, demand response, and reserves from the real-time SCED software. The definition of such shortage also includes discretionary operator inputs to the ASO (Ancillary Service Optimizer) or SCED software. For shortage pricing to be accurate, there must 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 accurately measure reserves. Without accurate measurement of reserves on a minute by minute basis, system operators cannot know with certainty that there is a shortage condition and a reliable trigger for five minute shortage pricing does not exist. The benefits of five minute shortage pricing are based on the assumption that a shortage can be precisely and transparently defined.[130]

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.[131] PJM did not propose any enhancements to reserve measurement in the January 11th compliance filing.

In the period between May 11, 2017, and December 31, 2017, there were instances when the real-time reserve data on the PJM website showed a shortage of synchronized reserves but there was not shortage pricing. The real-time reserves on the PJM website were operational reserves as measured by Energy Management System (EMS), and not the reserves dispatched and

130 See Comments of the Independent Market Monitor for PJM, Docket No. RM15-24-000 (December 1, 2015) at 9.
131 155 FERC ¶ 61,276 at P 177 (2016).

priced by SCED.[132] RT SCED estimated reserves based on generation dispatch with a 15 minute look ahead until July 16, 2017. On July 17, PJM reduced the RT SCED look-ahead from 15 minutes to 10 minutes, but the reserve levels used to define shortage pricing continue to be look-ahead estimates and not real time operational reserves. As a result, PJM's scarcity pricing does not reflect actual current scarcity conditions, but reflects the expected response of generation and forecast load 10 minutes in the future.[133]

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 and the goal of adding additional reserves.

Historical Performance During Spinning Events

All resources that respond to spinning events are paid for their response. Table 3-95 shows the performance of tier 1 and tier 2 synchronized reserves during spinning events declared in 2015, 2016, 2017, and the first nine months of 2018 that lasted at least 10 minutes. In 2015, tier 1 response MW 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. As a result, the 2015 estimates for tier 1 response were greater than 100 percent.

Beginning in 2016, PJM reported the response to spinning events only from the units that were part of its tier 1 estimate. In 2016, the tier 1 response rate was never greater than 85 percent, with an average response rate of 75 percent. In 2017, the tier 1 response rate was never greater than 75 percent, with an average response rate of 60 percent. In the first nine months of 2018, the average tier 1 response rate was 62 percent during the three spinning events that lasted for at least 10 minutes.

PJM's current approach to estimating tier 1 reserves is not an accurate basis for defining shortage and reflects, to an unknown degree, the goal of adding additional reserves above the defined target level.

132 PJM has since added the real-time SCED dispatched reserve quantities, in addition to the operational reserve quantities to its website.
133 Prior to July 17, 2017, PJM's scarcity pricing reflected the expected response of generation and load fifteen minutes in the future.

Table 3-95 Performance of synchronized reserves during spinning events: January 1, 2015 through September 30, 2018

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%
Jan 03, 2018 03	13	1,896.7	509.9	112.6	57.6	26.9%	51.2%
Apr 12, 2018 17	10	1,063.3	591.2	464.6	372.5	55.6%	80.2%
Jun 30, 2018 09	11	2,710.1	2,086.2	71.6	56.8	77.0%	79.3%
Jul 10, 2018 15	12	784.3	524.9	494.6	308.8	66.9%	62.4%
Aug 12, 2018 11	11	1,824.5	1,390.4	274.5	229.8	76.2%	83.7%
Sep 30, 2018 11	11	1,430.9	976.4	231.2	216.9	68.2%	93.8%

Tier 1 Synchronized Reserve Estimate Bias

Tier 1 synchronized reserves are calculated based on unit capabilities but are also subject to tier 1 estimate bias by PJM. PJM manually modifies (increasing or decreasing) the tier 1 synchronized reserve estimate of the market solution, forcing more or less tier 2 synchronized reserve and nonsynchronized reserve to clear to meet reserve requirements. Tier 1 biasing reflects the operators' view of the available tier 1 MW and operators' goal of adding additional reserves above the defined target level. Table 10-15 shows the average monthly biasing of tier 1 estimates in the Ancillary Service Optimizer (ASO) in 2017 and the first nine months of 2018.

There are no rules in the PJM tariff or manuals regarding the use of tier 1 MW biasing. With five minute shortage pricing and the associated market impacts, there is a clear need for explicit rules governing operator discretion to calculated reserves. The MMU has recommended since 2012 that PJM explicitly define the rules for using tier 1 biasing.

Generator Data used for Reserve Estimates

A potential source of error in calculating tier 1 MW is the use of the economic dispatch point to calculate the available ramp limited MW in 10 minutes rather than the actual output from the generator for any five minute interval. PJM addressed this issue partially in 2015 by adjusting a resource's available 10 minute ramp with Degree of Generator Performance metric (DGP).

PJM Cold Weather Operations 2018

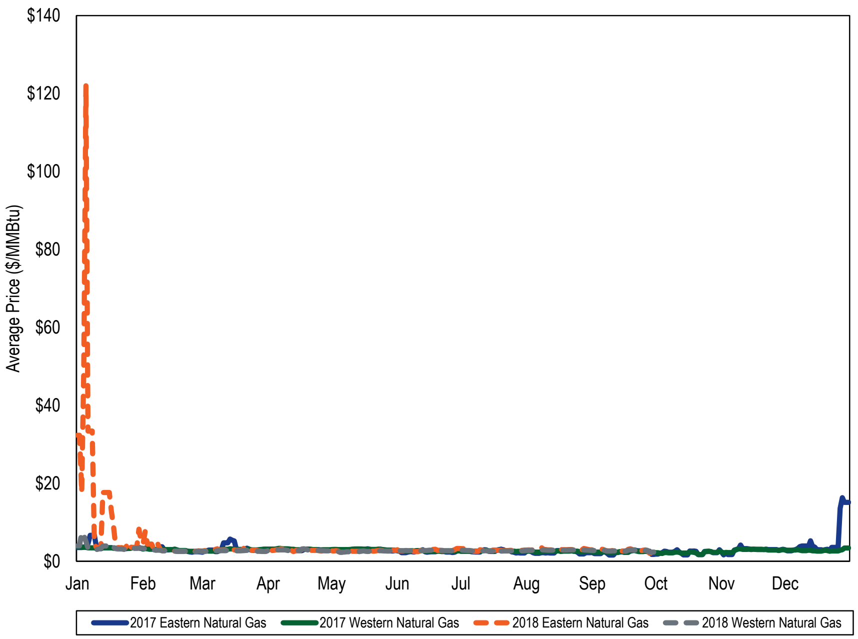
Natural Gas Supply and Prices

As of September 30, 2018, gas fired generation was 39.6 percent (73,090 MW) of the total installed PJM capacity (184,559.5 MW).[134] Figure 3-62 shows the average daily price of delivered natural gas for eastern and western parts of PJM service territory in 2018 and 2017.[135]

134 *2018 Quarterly State of the Market Report for PJM: January through September*, Section 5: Capacity Market, at Installed Capacity.

135 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.

Figure 3-62 Average daily delivered price for natural gas: 2017 through September 2018 ($/MMBtu)



During the first nine months of 2018, 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 demonstrates the potential benefits to creating a separate gas ISO/RTO structure to coordinate the supply of gas across pipelines and with the electric RTOs and to facilitate the interoperability of the pipelines in an explicit network.