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, 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 2019.

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 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 2019 was unconcentrated by FERC HHI standards in 98.2 percent of market hours and moderately concentrated in 1.8 percent of market hours. Average HHI was 773 with a minimum of 572 and a maximum of 1098 in the first nine months of 2019. The PJM energy market intermediate and peaking segments of supply were 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, 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 definition of cost-based offers and 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 they fail the TPS test.
- 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 2019 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). In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC). 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 2018 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 for some marginal units 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. Market design implementation issues, including inaccuracies in modeling of the transmission system and of generator capabilities as well as inefficiencies in real-time dispatch and price formation, undermine market efficiency in the energy market.

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 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

Supply and Demand

Market Structure

- **Supply.** Supply includes physical generation, imports and virtual transactions. The maximum average on-peak hourly offered real-time supply was 152,460 MW for summer of 2018 and 152,933 MW for summer of 2019. In the first nine months of 2019, 1,749.6 MW of new resources were added and 4,173.5 MW were retired.

  PJM average real-time cleared generation in the first nine months of 2019 decreased 29 MWh from the first nine months of 2018, from 95,561 MWh to 95,531 MWh.

  PJM average day-ahead cleared supply in the first nine months of 2019, including INCs and up to congestion transactions, increased by 2.5 percent from the first nine months of 2018, from 116,068 MWh to 118,913 MWh.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM accounting peak load in the first nine months of 2019 was 148,228 MWh in the HE 1800 on July 19, 2019, which was 1,185 MWh, 0.8 percent, higher than the PJM peak load for the first nine months of 2018, which was 147,042 MWh in the HE 1700 on August 28, 2018.

PJM average real-time demand in the first nine months of 2019 decreased by 2.3 percent from the first nine months of 2018, from 91,905 MWh to 89,834 MWh. PJM average day-ahead demand in the first nine months of 2019, including DECs and up to congestion transactions, increased by 2.3 percent from the first nine months of 2018, from 111,589 MWh to 114,133 MWh.

Market Behavior

- **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 2019, 26.3 percent were offered as available for economic dispatch, 30.4 percent were offered at their economic minimum, 4.2 percent were offered as emergency dispatch, 14.9 percent were offered as self scheduled, and 24.2 percent were offered as self scheduled and dispatchable.
- **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 2019, the average hourly increment offers submitted and cleared MW increased by 11.5 percent and 11.6 percent, from 5,725 MW and 2,568 MW in the first nine months of 2018 to 6,382 MW and 2,866 MW in the first nine months of 2019. The hourly average submitted and cleared decrement MW increased by 6.4 percent and 39.7 percent, from 6,854 MW and 2,841 MW in the first nine months of 2018 to 7,293 MW and 3,970 MW in the first nine months of 2019. The average hourly up to congestion submitted and cleared MW increased by 5.8 percent and 15.9 percent, from 60,031 MW and 17,638 MW in the first nine months of 2018 to 63,503 MW and 20,433 MW in the first nine months of 2019.

Market Performance

- **Generation Fuel Mix.** In the first nine months of 2019, coal units provided 24.5 percent, nuclear units 33.2 percent and natural gas units 36.0 percent of total generation. Compared to the first nine months of 2018, generation from coal units decreased 16.4 percent, generation from natural gas units increased 17.2 percent and generation from nuclear units decreased 1.9 percent.
- **Fuel Diversity.** In the first nine months of 2019, the fuel diversity of energy generation, measured by the fuel diversity index for energy (FDI_e), decreased 0.9 percent over the FDI_e for the first nine months of 2018.
- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first nine months of 2019, coal units were 27.2 percent and natural gas units were 69.7 percent of marginal resources. 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 PJM Day-Ahead Energy Market, in the first nine months of 2019, up to congestion transactions were 57.7 percent, INCs were 12.9 percent, DECs were 18.4 percent, and generation resources were 10.9 percent of marginal resources. In the first nine months of 2018, up to congestion transactions were 63.9 percent, INCs were 9.2 percent, DECs were 16.1 percent, and generation resources were 10.7 percent of marginal resources.
- **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 decreased in the first nine months of 2019 compared to the first nine months of 2018. The load-weighted, average real-time LMP was 30.0 percent lower in the first nine months of 2019 than in the first nine months of 2018, $27.60 per MWh versus $39.43 per MWh.

PJM day-ahead energy market prices decreased in the first nine months of 2019 compared to the first nine months of 2018. The load-weighted, average day-ahead LMP was 28.4 percent lower in the first nine months of 2019 than in the first nine months of 2018, $27.70 per MWh versus $38.71 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, in the first nine months of 2019, 26.8 percent of the load-weighted LMP was the result of coal costs, 42.7 percent was the result of gas costs and 0.9 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market, in the first nine months of 2019, 22.2 percent of the load-weighted LMP was the result of coal costs, 19.8 percent was the result of gas costs, 21.3 percent was the result of INC offers, 21.2 percent was the result of DEC bids, and 2.2 percent was the result of up to congestion transaction offers.

- **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 $0.48 per MWh in the first nine months of 2018 and -$0.11 per MWh in the first nine months of 2019. 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 27 intervals with five minute shortage pricing on 14 days in the first nine months of 2019. In all 27 intervals, synchronized reserves were short of the extended synchronized reserve requirement in the RTO and MAD reserve zones. In one of the 27 intervals, primary reserves were also short of the extended primary reserve requirement.
- There were 2,307 five minute intervals, or 2.9 percent of all five minute intervals in the first nine months of 2019 for which at least one solved SCED case showed a shortage of reserves, and 1,045 five minute intervals, or 1.3 percent of all five minute intervals in the first nine months of 2019 for which more than one solved SCED case showed a shortage of reserves. PJM operators used only 28 RT SCED cases that showed a shortage of reserves to calculate real-time LMPs and ancillary service prices.
- In the first nine months of 2019, PJM did not declare any emergency actions that triggered Performance Assessment Intervals (PAI).

Competitive Assessment

Market Structure

- **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.

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 0.1 percent in the first nine months of 2018 to 1.1 percent in the first nine months of 2019. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 1.0 percent in the first nine months of 2018 to 1.6 percent in the first nine months of 2019. 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 2019, 11 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 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 decreased from 0.1 percent in the first nine months of 2018 to 0.0 percent in the first nine months of 2019. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.1 percent in the first nine months of 2018 to 0.0 percent in the first nine months of 2019.
- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the first nine months of 2019, in the PJM Real-Time Energy Market, 97.6 percent of marginal units had offer prices less than $50 per MWh. The average dollar markup of units with offer prices less than $25 was positive ($0.18 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive ($1.77 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, 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 2019 was more than $400 per MWh while the highest markup in the first nine months of 2018 was more than $500 per MWh. During the period of cold weather and high demand in January 2018, several units in the PJM market were offered with high markups.

  In the first nine months of 2019, in the PJM Day-Ahead Energy Market, 98.4 percent of marginal generating units had offer prices less than $50 per MWh. The average dollar markup of units with offer prices less than $25 was positive ($0.48 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive ($1.38 per MWh) 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 2019 was about $90 per MWh, while the highest markup in the first nine months of 2018 was $200 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. Markup for gas fired units decreased in the first nine months of 2019.
- **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 units eligible for an FMU or AU adder for the period between December 2014

and August 2019. One unit qualified for an FMU adder for the month of September 2019.

Market Performance

- **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 2019, the unadjusted markup component of LMP was $1.95 per MWh or 7.1 percent of the PJM load-weighted, average LMP. June had the highest unadjusted peak markup component, $4.91 per MWh, or 14.1 percent of the real-time, peak hour load-weighted, average LMP. There were 39 hours in the first nine months of 2019 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded $34.39 per MWh.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In the first nine months of 2019, the unadjusted markup component of LMP resulting from generation resources was $0.67 per MWh or 2.4 percent of the PJM day-ahead load-weighted average LMP. July had the highest unadjusted peak markup component, $4.14 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.

Recommendations

Market Power

- The MMU recommends that the market rules explicitly require that offers in the 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 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 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: Adopted, 2018.)
- 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 in order to ensure effective market power mitigation, PJM always enforce parameter limited values by committing units only on parameter limited schedules, when the TPS test is failed or during high load conditions such as cold and hot weather alerts or more severe emergencies. (Priority: High. New recommendation. 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.)

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).

- 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 operators 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 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. First reported 2018. 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 implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM institute rules to assess a penalty for resources that choose to submit real-time values that are less flexible than their unit specific parameter limits or approved parameter limit exceptions based on tariff defined reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced, and based on inferior transportation service procured by the generator. (Priority: Medium. First reported Q1, 2019. 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: Partially adopted.)
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM 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 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, even if the MW are settled to the generator. 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, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not 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>.

- 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 document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not 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 operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not 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.)
- The MMU recommends that PJM model generators' operating transitions and peak operating modes. (Priority: Medium. New recommendation. Status: Not adopted.)

Transparency

- The MMU recommends that PJM market rules require the fuel type be identified for every price and cost schedule on an hourly basis 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.)
- The MMU recommends that PJM clearly define the criteria for operator approval of RT SCED cases used to send dispatch signals to resources and for pricing, to minimize operator discretion and implement a rule based approach. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM approve one RT SCED case for each five minute interval to send dispatch signals, and that PJM calculate prices for that five minute interval using the same approved SCED case. (Priority: High. New recommendation. Status: Not adopted.)

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first nine months of 2019, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, participation in demand response programs, virtual bids and offers, loads and prices.

PJM average real-time cleared generation decreased by 29 MWh, and peak load increased by 1,185 MWh, 0.8 percent, in the first nine months of 2019 compared to the first nine months of 2018. 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 both routinely and 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, under the PJM Market Rules, is not currently correct. The definition, that energy costs must be related to electric production, is not clear or correct. All costs and investments for power generation are related to electric production. Under this definition, some unit owners include costs that are not short run marginal costs in offers, especially 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 2019 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and 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. Prices in PJM are the result of input prices, consistent with a competitive market. Low natural gas prices have been a primary cause of low PJM energy market prices. 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 reserve pricing approach are attempting to 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, because PJM is not implementing scarcity pricing when there is scarcity. 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. Implementing scarcity pricing when there is scarcity is a basic first step. Targeted increases to the demand for reserves when the market is tight would address price formation in the energy market.

When the real-time security constrained economic dispatch (RT SCED) solution indicates a shortage of reserves, it should be used in calculating real-time prices and those prices should be applied to the market interval for which RT SCED calculated the shortage. There are significant issues with operator discretion and reluctance to approve RT SCED cases indicating shortage of reserves, and in using these cases to calculate prices. While it is appropriate for operators to ensure that cases that use erroneous inputs are not approved and not allowed to set prices, it is essential that operator discretion not extend beyond what is necessary and that operator discretion not prevent shortage pricing when there are shortage conditions. There are also issues with the alignment of SCED cases used for resource dispatch and the SCED cases used to calculate real-time prices. PJM should fix its current operating practices and ensure transparency regarding approval of SCED cases for resource dispatch and pricing so that market participants can have confidence in the market design to produce accurate and efficient price signals. These issues are even more critical now that PJM settles real-time energy transactions on a five minute basis.

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

The PJM defined inputs to the dispatch tools, particularly the real-time SCED, have substantial effects on energy market outcomes. Transmission line ratings, transmission penalty factors, load forecast bias, hydro resource schedules, and unit ramp rate adjustments change the dispatch of the system, affect prices, and can create price spikes through transmission line limit violations or restrictions on the resources available to resolve constraints. The automated adjustment of ramp rates by PJM, called Degree of Generator Performance (DGP), modifies the values offered by generators and limits the MW available to the RT SCED. PJM should evaluate its interventions in the market, consider whether the interventions are appropriate, and provide greater transparency to enhance market efficiency.

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 will be created by PJM's fast start pricing proposal as approved by FERC and would be created in a much more extensive form by PJM's convex hull pricing proposal and reserve pricing proposal.

Units that start in one hour are not fast start units, and their commitment costs are not marginal in a five minute market. The differences between the actual LMP and the fast start LMP will distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions. PJM will pay new forms of uplift in an attempt to counter the distorted incentives. The magnitude of the new payments and their effects on behavior are not well understood.

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 the 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, as in PJM's ORDC proposal, 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. Administrative scarcity pricing that establishes scarcity pricing in about 85 percent of hours, as PJM's ORDC proposal would, is not scarcity pricing but simply a revenue enhancement mechanism. When combined with PJM's failure to address the energy and ancillary services offset in the capacity market, PJM's ORDC filing is not consistent with efficient market design and is even more clearly just a revenue enhancement mechanism.

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 2019 or prior years. In the first nine months of 2019, marginal units were predominantly combined cycle gas generators with low fuel costs. The frequency of combined cycle gas as the marginal unit type has risen rapidly in the last three years, from 29.3 percent in the first nine months of 2016 to 62.2 percent in the first nine months of 2019. Overdue improvements in generator modeling in the energy market would allow PJM to more efficiently commit and dispatch combined cycle plants and to fully reflect the flexibility of these units. New combined cycle units placed competitive pressure on less efficient generators, and the market reliably served load with less congestion, less uplift, and less markup in marginal offers than in the first nine months of 2018. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants represents economic withholding. Given the structure of the energy market which can permit the exercise of aggregate market power, 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 cost-based offers and a reason for implementing an aggregate market power test. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2019.

Supply and Demand

Market Structure

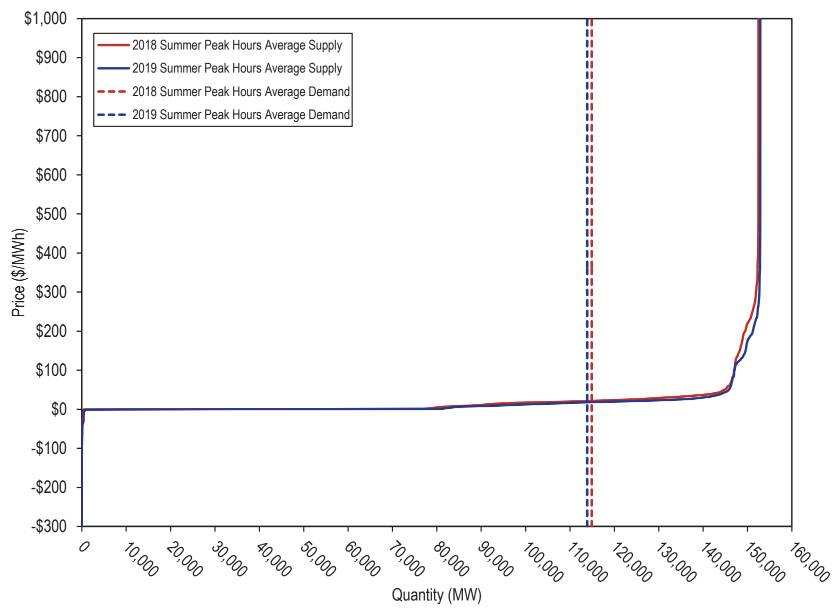
Supply

Supply includes physical generation, imports and virtual transactions.

In the first nine months of 2019, 1,749.6 MW of new resources were added and 4,173.5 MW were retired.

Figure 3-1 shows the average hourly real-time supply and demand for the on peak hours of summer of 2018 and 2019. [8] [9] [10] This figure reflects actual available MW from units that are online or offline and available to generate power in one hour, restricted by ramping capabilities.

Figure 3-1 Average hourly summer real-time supply curve comparison



8 Real-time generation offers and real-time import MWh are included.
9 Real-time load and export MWh are included.
10 The summer supply curve period is from June 1, to August 31.

Average hourly real-time supply curves are weather sensitive. Figure 3-2 shows the typical dispatch range curve.

Figure 3-2 Typical dispatch range of average hourly summer real-time supply curves

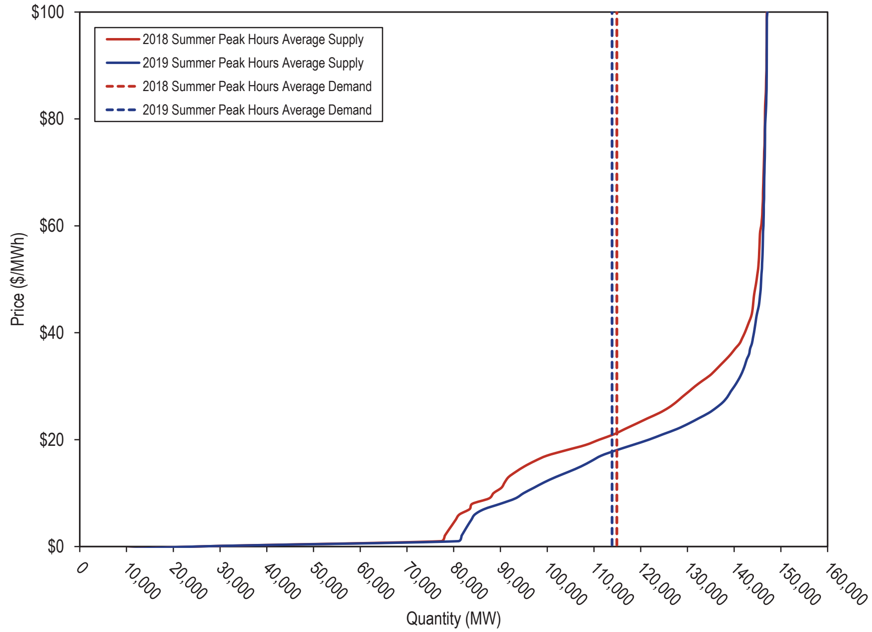


Table 3-2 shows the price elasticity of supply for the on peak summer hours of 2018 and 2019 by load level. The price elasticity of supply measures the responsiveness of the quantity supplied (MWh) to a change in price:

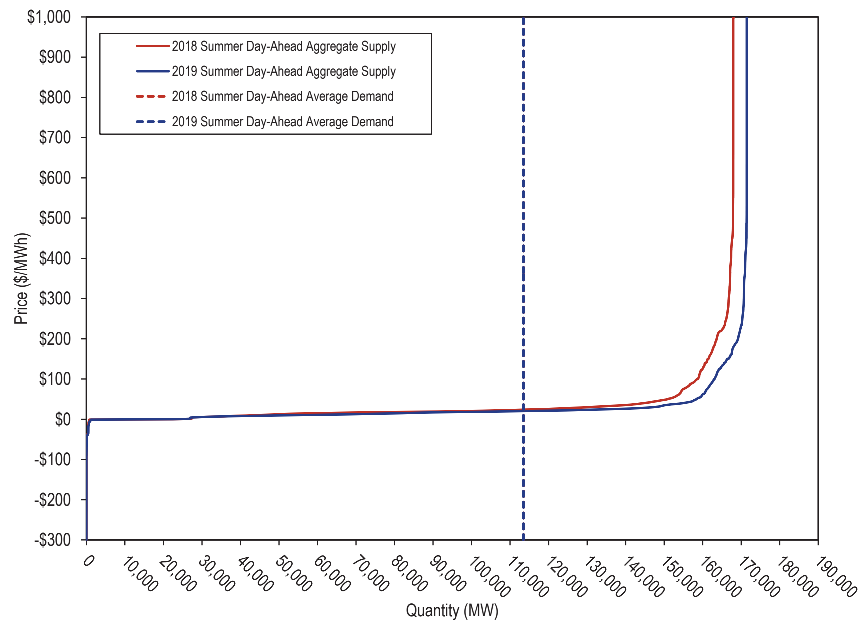
Elasticity of Supply = Percent change in quantity supplied / Percent change in price.

Table 3-2 Price Elasticity of Supply

	Elasticity of Supply	
GWh	2018 Summer	2019 Summer
75-95	0.018	0.020
95-115	0.538	0.302
115-135	0.326	0.414
135-Max	0.004	0.003

Figure 3-3 is the PJM day-ahead generation aggregate supply curve, which includes all day-ahead hourly supply for the peak summer hours of 2018 and 2019.[11]

Figure 3-3 PJM day-ahead generation aggregate supply curve: 2018 summer and 2019 summer



11 Day-ahead generation offers, INC bid MWh, Day-ahead import MWh are included. UTCs are not included due to lack of pricing point.

Real-Time Supply

The maximum of average on-peak hourly offered real-time supply was 152,460 MWh for the summer of 2018, and 152,933 MWh for the summer of 2019. Real-time supply at a defined time is restricted by unit ramp limits and start times. Therefore, the available supply at a defined time is less than the total capacity of the PJM system.

PJM average real-time cleared generation in the first nine months of 2019 decreased from the first nine months of 2018, from 95,561 MWh to 95,531 MWh.[12]

PJM average real-time cleared supply including imports in the first nine months of 2019 decreased by 1.0 percent from the first nine months of 2018, from 97,588 MWh to 96,659 MWh.

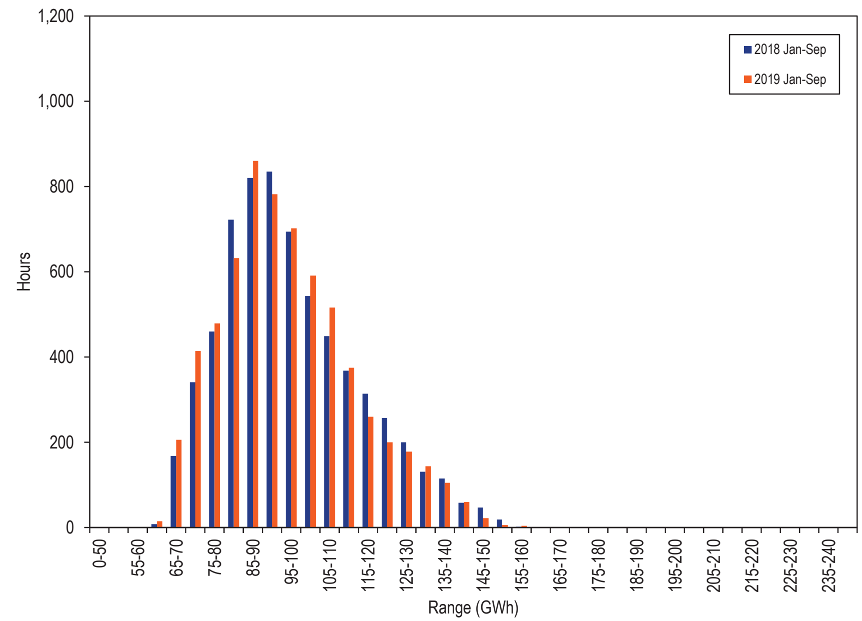
In the PJM Real-Time Energy Market, there are three types of supply offers:

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

PJM Real-Time Supply Frequency

Figure 3-4 shows the hourly distribution of PJM real-time generation plus imports for the first nine months of 2018 and 2019.

Figure 3-4 Distribution of real-time generation plus imports: January through September, 2018 and 2019[13]



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

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

PJM Real-Time, Average Supply

Table 3-3 presents real-time hourly supply summary statistics for the first nine months of each year in the 19 year period from 2001 through 2019.

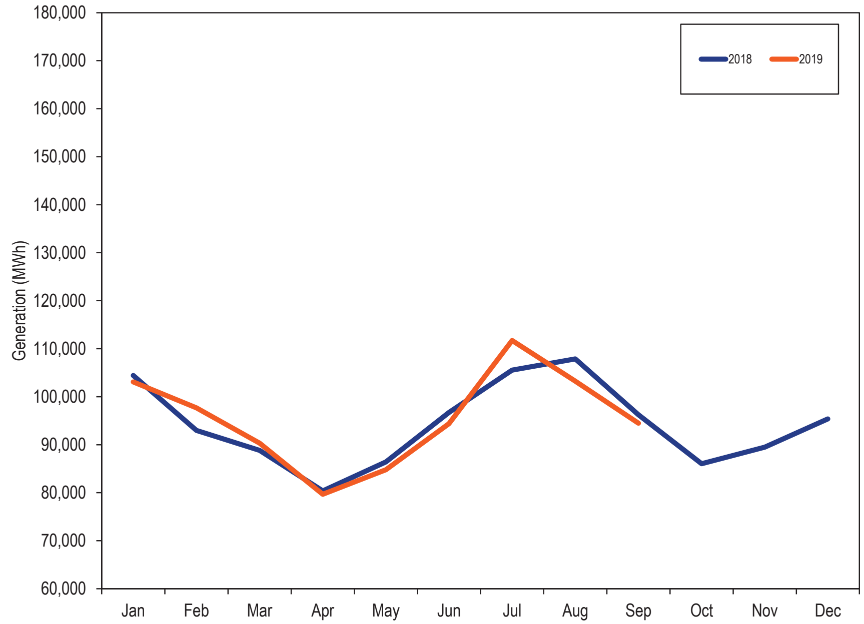
Table 3-3 Average hourly real-time generation and real-time generation plus imports: January through September, 2001 through 2019

	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
2001	30,304	5,216	33,299	5,571	NA	NA	NA	NA
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%
2019	95,531	17,206	96,659	17,378	(0.0%)	(1.7%)	(1.0%)	(2.1%)

PJM Real-Time, Monthly Average Generation

Figure 3-5 compares the real-time, monthly average hourly generation in 2018 and the first nine months of 2019.

Figure 3-5 Real-time monthly average hourly generation: January 2018 through September 2019



Day-Ahead Supply

PJM average hourly, day-ahead cleared supply in the first nine months of 2019, including INCs and up to congestion transactions, increased by 2.5 percent from the first nine months of 2018, from 116,068 MWh to 118,913 MWh.

PJM average hourly, day-ahead cleared supply in the first nine months of 2019, including INCs, up to congestion transactions, and imports, increased by 2.4 percent from the first nine months of 2018, from 116,471 MWh to 119,249 MWh.

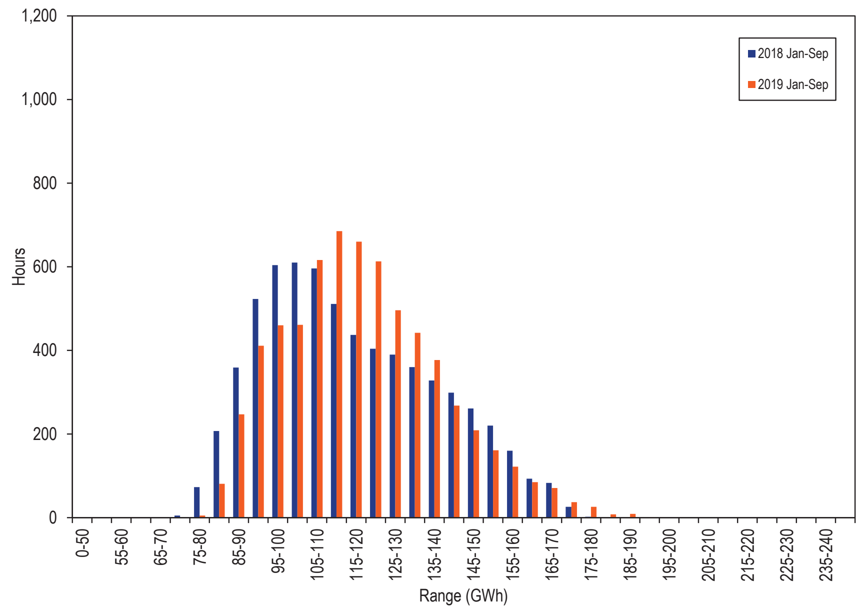
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MW, 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 MW and corresponding offer prices from a unit.
- **Increment Offer (INC).** Financial offer to supply MW 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 for a specific amount of MW between the transaction source and sink. An up to congestion transaction is a matched pair of an injection and a withdrawal.
- **Import.** An import is an external energy transaction for a specific MW amount scheduled to PJM from another balancing authority. An import must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An import energy transaction that clears the Day-Ahead Energy Market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an import energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the real-time energy market scheduling process.

PJM Day-Ahead Supply Duration

Figure 3-6 shows the hourly distribution of PJM day-ahead supply, including increment offers, up to congestion transactions, and imports for first nine months of 2018 and 2019.

Figure 3-6 Distribution of day-ahead supply plus imports: January through September, 2018 and 2019[14]



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

PJM Day-Ahead, Average Supply

Table 3-4 presents day-ahead hourly supply summary statistics for the first nine months of the 19-year period from 2001 through 2019.

Table 3-4 Average hourly day-ahead supply and day-ahead supply plus imports: January through September, 2001 through 2019

	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
2001	27,519	4,839	28,279	4,911	NA	NA	NA	NA
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%
2019	118,913	20,009	119,249	19,989	2.5%	(8.8%)	2.4%	(8.9%)

PJM Day-Ahead, Monthly Average Supply

Figure 3-7 compares the day-ahead, monthly average hourly supply, including increment offers and up to congestion transactions for 2018 and first nine months of 2019.

Figure 3-7 Day-ahead monthly average hourly supply: January 2018 through September 2019

Real-Time and Day-Ahead Supply

Table 3-5 presents summary statistics for the first nine months of 2018 and 2019, for day-ahead and real-time supply. All data are cleared MWh. The last two columns of Table 3-5 are the day-ahead supply minus the real-time supply. The first of these columns is the total physical day-ahead generation less the total physical real-time generation and the second of these columns is the total day-ahead supply less the total real-time supply. In the first nine months of 2019, up to congestion transactions were 17.1 percent of the total day-ahead supply compared to 15.1 percent in the first nine months of 2018.

Table 3-5 Day-ahead and real-time supply (MWh): January through September, 2018 and 2019

		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	2018	95,852	2,577	17,639	403	116,471	95,561	97,588	18,883	291
	2019	95,616	2,866	20,430	337	119,249	95,531	96,659	22,590	85
Median	2018	93,293	2,470	15,754	362	112,889	92,551	94,608	18,281	742
	2019	93,534	2,735	20,316	295	117,016	93,083	94,316	22,700	451
Standard Deviation	2018	17,680	1,084	8,143	246	21,939	17,506	17,747	4,192	174
	2019	17,824	1,018	4,442	228	19,989	17,206	17,378	2,611	619
Peak Average	2018	105,389	3,137	18,713	383	127,622	104,480	106,732	20,891	910
	2019	105,288	3,357	21,849	289	130,783	104,446	105,631	25,153	842
Peak Median	2018	102,804	3,108	16,630	333	126,398	101,231	103,411	22,988	1,573
	2019	103,456	3,300	21,695	223	128,196	102,364	103,558	24,638	1,091
Peak Standard Deviation	2018	15,532	1,086	8,633	266	19,750	15,968	15,996	3,754	(436)
	2019	15,486	996	4,249	225	17,004	15,492	15,648	1,356	(6)
Off-Peak Average	2018	87,512	2,088	16,700	420	106,720	87,762	89,592	17,128	(250)
	2019	87,159	2,436	19,190	378	109,164	87,737	88,814	20,350	(578)
Off-Peak Median	2018	84,670	2,020	14,967	380	102,006	84,785	86,452	15,554	(115)
	2019	84,599	2,337	19,038	345	106,758	85,398	86,319	20,439	(799)
Off-Peak Standard Deviation	2018	15,030	811	7,566	225	18,904	14,872	15,153	3,752	158
	2019	15,249	824	4,231	223	16,678	14,657	14,834	1,843	592

Figure 3-8 shows the average hourly cleared volumes of day-ahead supply and real-time supply for the first nine months of 2019. 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 3-8 Day-ahead and real-time supply (Average hourly volumes): January through September, 2019

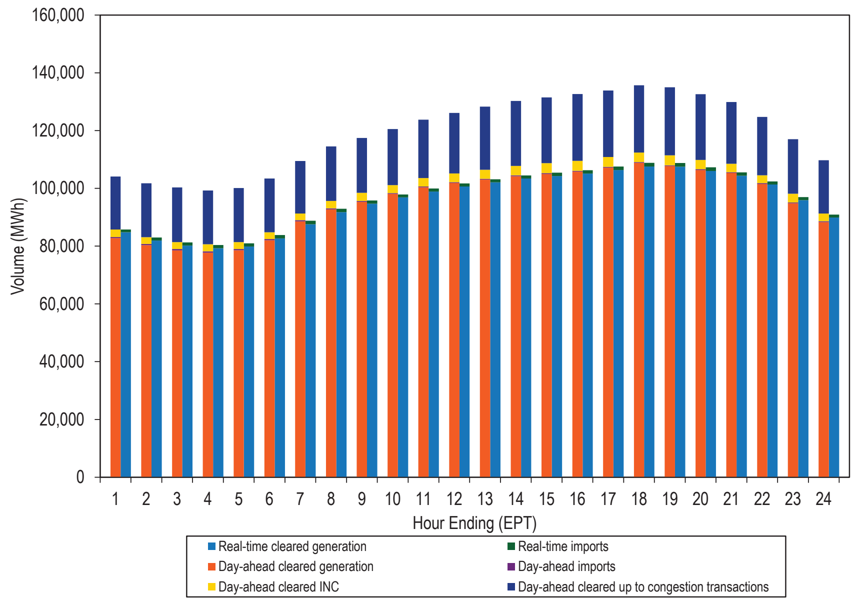
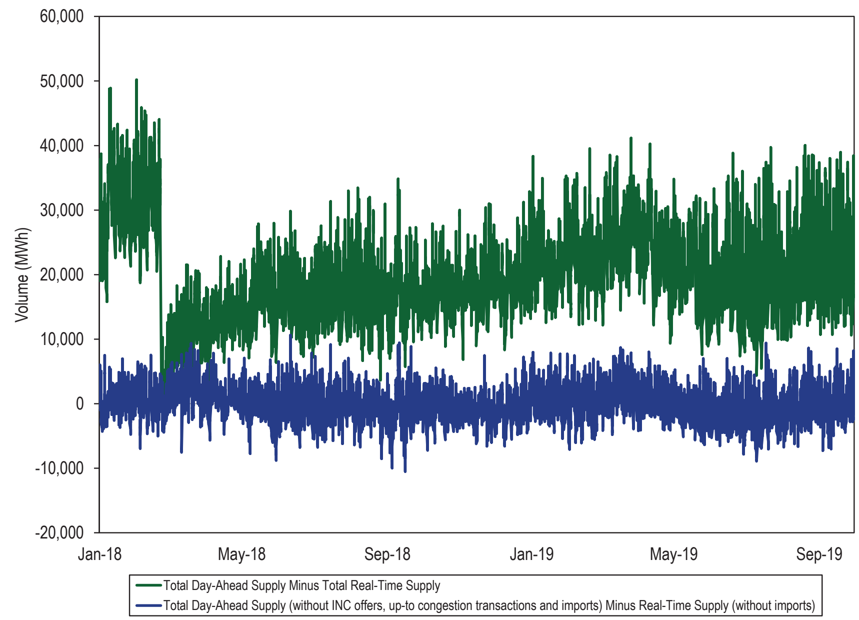


Figure 3-9 shows the difference between the day-ahead and real-time average daily supply for 2018 and the first nine months of 2019.

Figure 3-9 Difference between day-ahead and real-time supply (Average daily volumes): January 2018 through September 2019



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.[15]

The PJM system real-time hourly peak load in the first nine months of 2019 was 148,228 MWh in the HE 1800 on July 19, 2019, which was 1,185 MWh, or 0.8 percent, more than the peak load in the first nine months of 2018, which was 147,042 MWh in the HE 1700 on August 28, 2018.

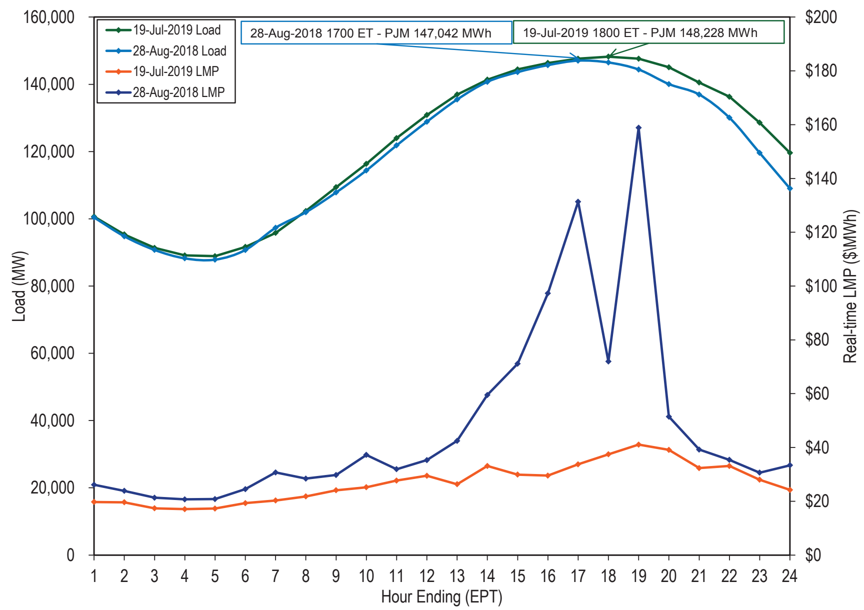
Table 3-6 shows the peak loads for the first nine months of 2009 through 2019.

Table 3-6 Actual footprint peak loads: January through September, 2009 to 2019[16 17]

(Jan - Sep)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
2009	Mon, August 10	17	123,900	NA	NA
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%
2019	Fri, July 19	18	148,228	1,185	0.8%

Figure 3-10 compares the peak load days during the first nine months of 2018 and 2019. The average real-time LMP for the July 19, 2019 peak load hour was $37.47 and for the August 28, 2018 peak load hour was $131.36.

Figure 3-10 Peak-load comparison Tuesday, August 28, 2018 and Friday, July 19, 2019



15 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.

16 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>.

17 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.

Real-Time Demand

PJM average hourly real-time demand in the first nine months of 2019 decreased by 2.3 percent from the first nine months of 2018, from 91,905 MWh to 89,834 MWh.[18]

PJM average hourly real-time demand including exports in the first nine months of 2019 decreased by 0.9 percent from the first nine months of 2018, from 95,795 MWh to 94,918 MWh.

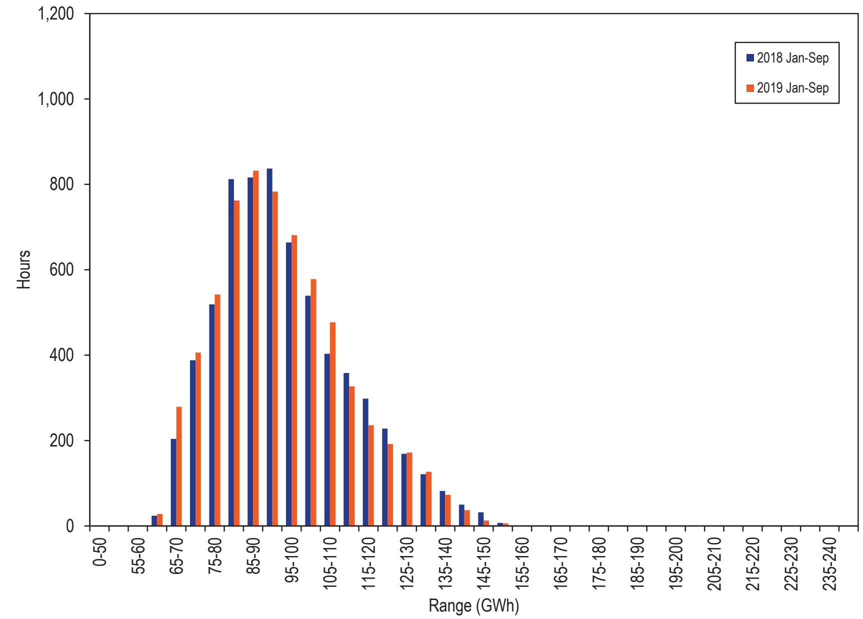
In the PJM Real-Time Energy Market, there are two types of demand:

- **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 3-11 shows the hourly distribution of PJM real-time load plus exports for the first nine months of 2018 and 2019.[19]

Figure 3-11 Distribution of real-time accounting load plus exports: January through September, 2018 and 2019[20]



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

19 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>.

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

PJM Real-Time, Average Load

Table 3-7 presents real-time hourly demand summary statistics for the first nine months of 2001 to 2019. 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.[21]

Table 3-7 Real-time load and real-time load plus exports: January through September, 2001 through 2019

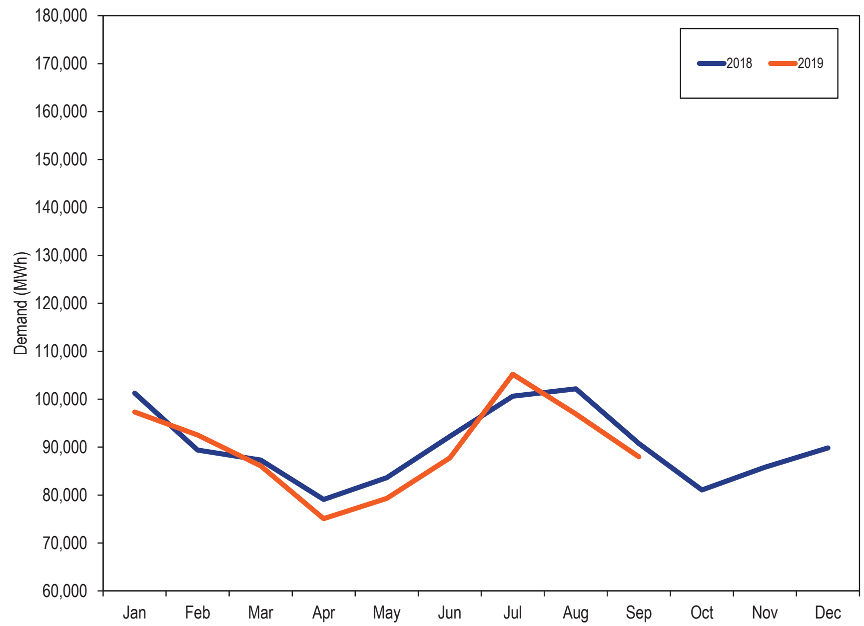
	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Jan-Sep	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
2001	31,060	6,156	32,900	5,861	NA	NA	NA	NA
2002	35,715	8,688	37,367	8,878	15.0%	41.1%	13.6%	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	91,905	17,064	95,795	17,245	5.3%	6.6%	4.2%	9.2%
2019	89,834	16,794	94,918	16,924	(2.3%)	(1.6%)	(0.9%)	(1.9%)

21 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 3-12 compares the real-time, monthly average hourly loads for 2018 and the first nine months of 2019.

Figure 3-12 Real-time monthly average hourly load: January 2018 through September 2019



PJM real-time load is significantly affected by temperature. Table 3-8 compares the PJM monthly heating and cooling degree days in the first nine months of 2018 and 2019.[22] Heating degree days decreased 6.4 percent, and cooling degree days decreased 5.9 percent compared to the first nine months of 2018.

22 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

Table 3-8 Heating and cooling degree days: January 2018 through September 2019

	2018		2019		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	941	0	909	0	(3.4%)	0.0%
Feb	575	0	688	0	19.7%	0.0%
Mar	658	0	607	0	(7.8%)	0.0%
Apr	359	1	145	0	(59.6%)	(77.0%)
May	0	139	23	90	0.0%	(35.8%)
Jun	0	245	0	210	0.0%	(14.3%)
Jul	0	363	0	423	0.0%	16.6%
Aug	0	363	0	312	0.0%	(14.1%)
Sep	0	213	0	211	0.0%	(0.6%)
Oct	207	65				
Nov	566	0				
Dec	675	0				
Jan-Sep	2,532	1,324	2,372	1,246	(6.4%)	(5.9%)

Day-Ahead Demand

PJM average day-ahead demand in the first nine months of 2019, including DECs and up to congestion transactions, increased by 2.3 percent from the first nine months of 2018, from 111,589 MWh to 114,133 MWh.

PJM average day-ahead demand in the first nine months of 2019, including DECs, up to congestion transactions, and exports, increased by 2.3 percent from of the first nine months of 2018, from 114,373 MWh to 117,048 MWh.

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

- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A DEC can be submitted by any market participant.
- **Up to Congestion Transaction (UTC).** A conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up to congestion transaction is evaluated as a matched pair of an injection and a withdrawal.
- **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.

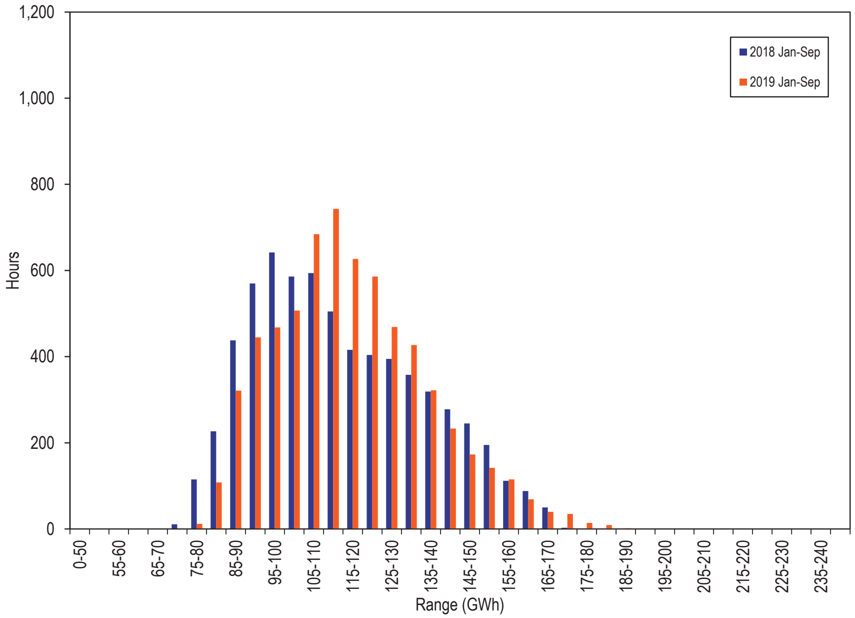
PJM day-ahead demand is the hourly total of the five types of cleared demand bids.

PJM Day-Ahead Demand Duration

Figure 3-13 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up to congestion transactions, and exports for the first nine months of 2018 and 2019.

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.

Figure 3-13 Distribution of day-ahead demand plus exports: January through September, 2018 and 2019[23]



PJM Day-Ahead, Average Demand

Table 3-9 presents day-ahead hourly demand summary statistics for the first nine months of each year from 2001 to 2019.

Table 3-9 Average hourly day-ahead demand and day-ahead demand plus exports: January through September, 2001 through 2019

	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
2001	33,944	7,016	34,444	6,817	NA	NA	NA	NA
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%
2019	114,133	19,233	117,048	19,465	2.3%	(9.3%)	2.3%	(9.0%)

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

PJM Day-Ahead, Monthly Average Demand

Figure 3-14 compares the day-ahead, monthly average hourly demand, including decrement bids and up to congestion transactions in 2018 and the first nine months of 2019.

Figure 3-14 Day-ahead monthly average hourly demand: January 2018 through September 2019

Real-Time and Day-Ahead Demand

Table 3-10 presents summary statistics for the first nine months of 2018 and 2019 day-ahead and real-time demand. All data are cleared MWh. The last two columns of Table 3-10 are the day-ahead demand minus the real-time demand. The first such column is the total physical day-ahead load (fixed demand plus price-sensitive demand) less the physical real-time load and the second such column is the total day-ahead demand less the total real-time demand.

Table 3-10 Cleared day-ahead and real-time demand (MWh): January through September, 2018 and 2019

		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	2018	88,840	2,258	2,851	17,639	2,784	114,373	91,905	95,795	18,578	(807)
	2019	88,424	1,309	3,970	20,430	2,915	117,048	89,834	94,918	22,130	(102)
Median	2018	86,670	2,296	2,539	15,754	2,687	110,917	89,193	92,919	17,998	(228)
	2019	86,655	1,320	3,595	20,316	2,799	114,900	87,550	92,608	22,292	424
Standard Deviation	2018	16,252	570	1,413	8,143	933	21,392	17,064	17,245	4,148	(242)
	2019	16,136	234	1,705	4,442	782	19,465	16,794	16,924	2,541	(423)
Peak Average	2018	98,048	2,490	3,176	18,713	2,837	125,263	100,932	104,723	20,541	(394)
	2019	97,584	1,437	4,418	21,849	3,016	128,305	98,591	103,696	24,609	431
Peak Median	2018	95,515	2,687	2,927	16,630	2,716	124,075	97,793	101,406	22,669	409
	2019	95,861	1,461	4,123	21,695	2,943	125,655	96,633	101,682	23,973	689
Peak Standard Deviation	2018	13,911	552	1,386	8,633	925	19,250	15,023	15,534	3,717	(560)
	2019	13,858	224	1,715	4,249	826	16,575	14,902	15,226	1,350	(819)
Off-Peak Average	2018	80,789	2,056	2,567	16,700	2,738	104,850	84,013	87,989	16,861	(1,168)
	2019	80,415	1,196	3,578	19,190	2,827	107,206	82,178	87,242	19,963	(567)
Off-Peak Median	2018	78,412	2,210	2,211	14,967	2,672	100,275	81,210	85,003	15,272	(588)
	2019	78,444	1,203	3,214	19,038	2,707	104,883	79,913	84,865	20,018	(266)
Off-Peak Standard Deviation	2018	13,673	505	1,376	7,566	937	18,423	14,661	14,691	3,732	(483)
	2019	13,515	179	1,596	4,231	731	16,197	14,453	14,419	1,778	(759)

Figure 3-15 shows the average hourly cleared volumes of day-ahead demand and real-time demand for the first nine months of 2019. 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 3-15 Day-ahead and real-time demand (Average hourly volumes): January through September, 2019

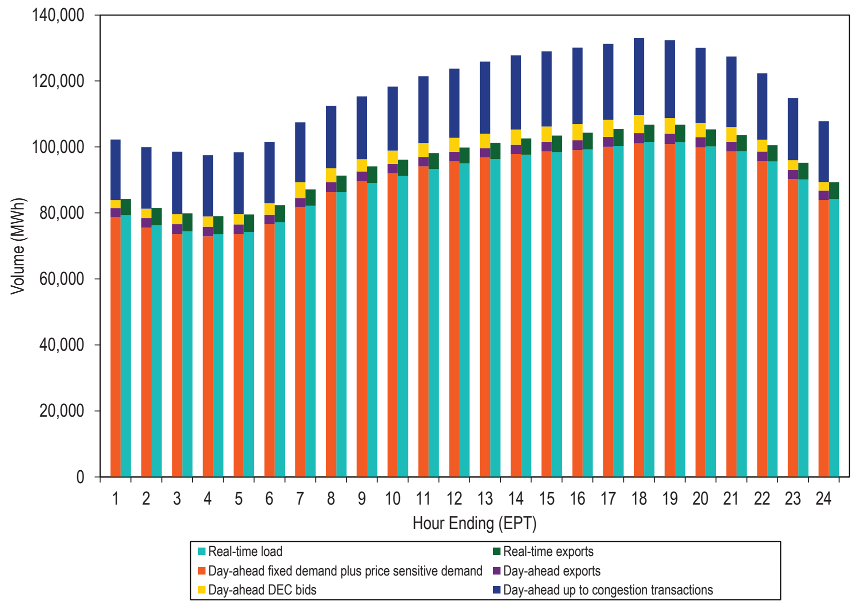
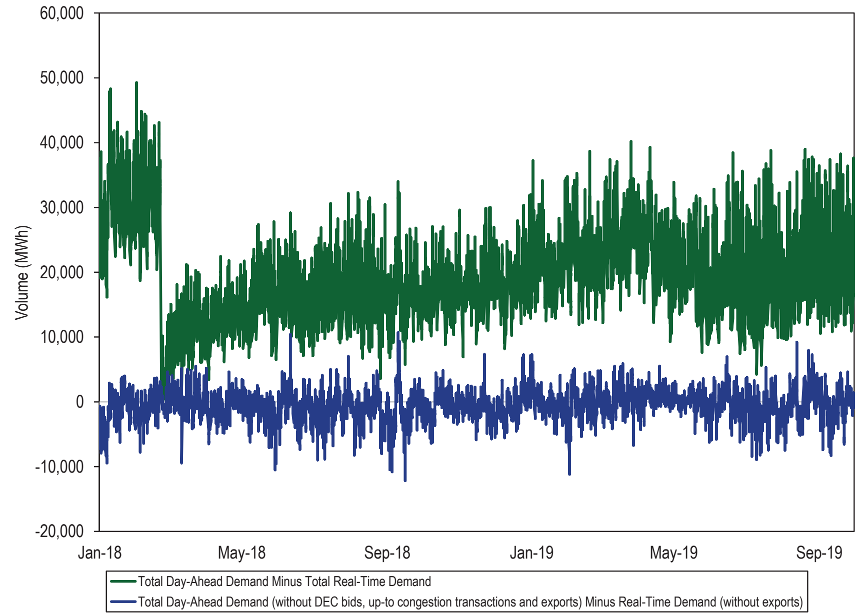


Figure 3-16 shows the difference between the day-ahead and real-time average daily demand for 2018 and the first nine months of 2019.

Figure 3-16 Difference between day-ahead and real-time demand (Average daily volumes): January 2018 through September 2019



Market Behavior

Generator Offers

Generator offers are categorized as dispatchable (Table 3-11) or self scheduled (Table 3-12).[24] Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are self scheduled and must run. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are self scheduled and dispatchable. Table 3-11 and Table 3-12 do not include units that did not indicate their offer status 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. Generators may have multiple available offers. In order to select one offer, if there are active emergency conditions a PLS offer is used, if there is no active emergency the lowest price-based offer is used, if there is no price-based offer a cost-based offer is used, and if there are multiple cost-based offers the cheapest commitment cost-based offer is used.

Table 3-11 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 2019. For example, 39.9 percent of all CC offer MW were the economic minimum offered MW and 33.3 percent of CC offer MW 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, including the economic minimum and emergency MW. For example, 77.3 percent of all CC unit offers were dispatchable, including the 39.9 percent of economic minimum MW and 3.6 percent of emergency MW offered by CC units. The dispatchable range of a unit is between the economic minimum and emergency range. For example, 33.8 percent of all CC unit offers have an economic dispatch range. 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, 23.2 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 2019, 26.3 percent of all dispatchable offers have an economic dispatch range.

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

Table 3-11 Distribution of day-ahead MW for dispatchable unit offer prices: January through September, 2019

		Dispatchable (Range)							
Unit Type	Economic Minimum	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	39.9%	0.0%	33.3%	0.4%	0.1%	0.0%	0.0%	3.6%	77.3%
CT	64.6%	0.0%	24.0%	2.4%	0.5%	0.0%	0.0%	7.3%	98.8%
Diesel	39.3%	0.0%	16.4%	4.8%	0.0%	0.0%	0.0%	16.8%	77.3%
Nuclear	5.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.9%
Pumped Storage	0.0%	0.0%	12.4%	0.0%	0.0%	0.0%	0.0%	39.9%	52.3%
Run of River	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
Solar	0.1%	0.0%	15.0%	0.0%	0.0%	0.0%	0.0%	0.0%	15.1%
Steam - Coal	21.8%	0.0%	26.6%	0.0%	0.0%	0.0%	0.0%	1.2%	49.6%
Steam - Other	29.2%	0.0%	49.2%	1.7%	0.4%	0.0%	0.0%	3.1%	83.6%
Wind	1.0%	0.0%	8.9%	0.0%	0.0%	0.0%	0.0%	1.0%	10.8%
All Dispatchable Offers	30.4%	0.0%	23.2%	0.7%	0.1%	0.0%	0.0%	4.2%	60.9%

Table 3-12 shows the proportion of day-ahead MW offers by unit type that were self scheduled to generate fixed output by unit type and price range for self scheduled and dispatchable units, for the first nine months of 2019. For example, 10.5 percent of CC offer MW were the economic minimum and 10.4 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, 22.7 percent of all CC offers were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including the 1.5 percent of emergency MW offered by CC units. The all self scheduled offers row is the proportion of MW that were offered as either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum within a given range by all unit types. For example, units that were self scheduled to generate at fixed output accounted for 14.9 percent of all offers and self scheduled and dispatchable units accounted for 23.2 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 2019, 14.3 percent were offered as self scheduled and 24.2 percent were offered as self scheduled and dispatchable.

Table 3-12 Distribution of day-ahead MW for self scheduled and dispatchable unit offer prices: January through September, 2019

	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	0.2%	0.1%	10.5%	0.0%	10.4%	0.0%	0.0%	0.0%	0.0%	1.5%	22.7%
CT	0.2%	0.0%	0.6%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.1%	1.2%
Diesel	16.5%	0.0%	2.0%	0.0%	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	20.0%
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	65.4%	0.0%	23.0%	0.0%	2.2%	0.0%	0.0%	0.0%	0.0%	0.0%	90.6%
Pumped Storage	4.2%	5.4%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	9.9%
Run of River	86.8%	11.9%	0.0%	0.0%	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	99.7%
Solar	10.1%	2.6%	0.0%	0.0%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%	14.3%
Steam - Coal	2.1%	0.7%	23.0%	0.0%	22.5%	0.0%	0.1%	0.0%	0.1%	1.7%	50.3%
Steam - Other	3.6%	0.7%	5.8%	0.0%	3.6%	0.2%	0.0%	0.0%	0.0%	0.6%	14.5%
Wind	6.7%	6.7%	2.6%	0.0%	0.8%	0.0%	0.0%	0.0%	0.0%	2.6%	19.4%
All Self-Scheduled Offers	14.3%	0.6%	13.2%	0.0%	9.0%	0.0%	0.0%	0.0%	0.0%	0.9%	39.1%

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 means the ability to make changes to an offer after the day-ahead rebid period. All participants are able to make hourly offers. Participants must opt in on a monthly basis to make intraday offer updates. Table 3-13 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 2019, a daily average of 327 natural gas fired units had opted in for intraday offer updates out of a daily average of 449 natural gas fired units. This is a decrease of 1.6 percent from the daily average number of natural gas fired units that opted in to intraday offer updates in December 2018.

Table 3-13 Average number of units opted in for intraday offers by month: 2018 and 2019

	2018						2019					
	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	289.0	32.0	321.0	444.0	394.7	838.7	334.0	37.0	371.0	447.9	358.6	806.5
Feb	300.0	32.0	332.0	444.0	395.7	839.7	334.0	37.0	371.0	447.3	355.7	803.0
Mar	302.0	32.0	334.0	444.5	394.6	839.0	334.0	37.0	371.0	447.1	354.3	801.4
Apr	310.6	32.0	342.6	445.9	394.0	839.9	334.0	37.0	371.0	447.5	353.3	800.7
May	323.5	32.0	355.5	444.9	393.2	838.0	334.5	37.0	371.5	449.9	354.1	804.0
Jun	326.0	32.0	358.0	443.3	369.8	813.1	335.0	37.0	372.0	449.4	352.9	802.3
Jul	326.0	34.0	360.0	443.0	367.4	810.5	335.5	37.0	372.5	449.0	350.2	799.2
Aug	326.0	36.0	362.0	445.0	363.7	808.7	327.0	37.2	364.2	449.0	348.8	797.8
Sep	326.0	36.0	362.0	445.2	360.1	805.3	327.0	44.0	371.0	449.0	347.4	796.4
Oct	326.0	36.0	362.0	446.5	360.1	806.6						
Nov	330.0	37.0	367.0	447.8	360.5	808.3						
Dec	332.4	37.0	369.4	448.4	360.2	808.5						

Table 3-14 shows the average number of units that made hourly differentiated offers in the day-ahead market or rebid period. In September 2019, an average of 321.6 units made hourly differentiated offers. This is an increase of 19.4 percent from the average number of units that made hourly differentiated offers in December 2018.

Table 3-14 Average number of units with hourly differentiated offers by month: 2018 and 2019

	2018			2019		
	Natural Gas	Other Fuels	Total	Natural Gas	Other Fuels	Total
Jan	207.0	12.4	219.4	252.3	15.8	268.0
Feb	214.4	10.5	224.9	262.6	16.9	279.5
Mar	215.0	11.6	226.6	265.6	17.0	282.5
Apr	231.3	11.4	242.8	280.6	22.8	303.4
May	242.6	11.8	254.4	298.5	24.5	322.9
Jun	246.6	9.0	255.6	296.0	23.7	319.7
Jul	247.0	11.3	258.3	300.4	23.7	324.0
Aug	259.6	16.6	276.2	314.4	23.4	337.7
Sep	238.2	14.9	253.1	300.1	21.5	321.6
Oct	252.6	17.9	270.5			
Nov	261.9	25.6	287.6			
Dec	244.7	24.6	269.4			

Table 3-15 shows the average number of units that made rebid offer updates and intraday offer updates. In September 2019, an average of 135.6 units made intraday offer updates. This is an increase of 12.1 percent from the average number of units that made intraday offer updates in December 2018.

Table 3-15 Average number of units making rebid or intraday offer updates by month: 2018 and 2019

	2018			2019		
	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	114.1	3.8	117.8	134.5	11.7	146.3
Feb	117.3	4.9	122.2	132.5	5.2	137.7
Mar	113.5	6.2	119.7	143.9	5.3	149.2
Apr	116.8	5.2	122.0	132.3	5.6	137.9
May	122.2	4.8	127.0	137.6	6.1	143.7
Jun	124.7	4.4	129.1	139.8	5.9	145.7
Jul	128.1	4.4	132.5	129.5	5.4	134.8
Aug	130.2	3.4	133.6	136.0	7.4	143.4
Sep	124.3	4.3	128.6	127.4	8.2	135.6
Oct	132.0	3.9	135.9			
Nov	127.2	4.5	131.6			
Dec	116.4	4.7	121.0			

Parameter Limited Schedules

Cost-Based Offers

All capacity resources in PJM are required to submit at least one cost-based offer. For the 2018/2019 and 2019/2020 delivery years, PJM procured two types of capacity resources, capacity performance resources and base capacity resources. Since June 1, 2018, there are no longer any RPM resources committed as the legacy annual capacity product that existed prior to the 2018/2019 Delivery Year. 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. For all resources, a parameter limited schedule is to be used by PJM for committing generation resources that fail the Three Pivotal Supplier (TPS) test.

The MMU recommends that in order to ensure effective market power mitigation, PJM always enforce parameter limited values when the TPS test is failed or during high load conditions such as cold and hot weather alerts or emergency conditions. Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the price-based parameter limited schedule during hot and cold weather alerts. Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the cost-based parameter limited schedule when a resource fails the TPS test.

Currently, there are no rules in the PJM tariff or manuals that limit the markup 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 and during high load conditions such as cold and hot weather alerts or more severe emergencies, 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 Limits

For generation capacity resources committed prior to the implementation of the capacity performance rules, the parameters that were subject to limits on their parameter limited schedules were Minimum Run Time, Minimum Down Time, Maximum Daily Starts, Maximum Weekly Starts, and Turn Down Ratio. The limits for these parameters were based on the parameter limited schedule matrix in the PJM operating agreement.[25] Startup times and notification times were not subject to limits. Market sellers could request exceptions to the limits in the matrix on a temporary basis, for up to 30 days, for physical issues that occur at the units at any time during the delivery year. Market sellers could also request longer term exceptions, called period exceptions, supported by technical documentation and historical operating data, submitted in advance

25 See PJM Operating Agreement Schedule 1 § 6.6 (c).

of a delivery year, which were reviewed by PJM and the MMU and approved by PJM. In the PJM energy market, market sellers were required to submit operating parameters in their parameter limited schedules that were at least as flexible as the limits specified in the parameter limited schedule matrix, or an approved exception.

Beginning in the 2016/2017 Delivery Year, resources that had capacity performance (CP) commitments were 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. Startup and notification times are limited for capacity performance resources beginning June 1, 2016, and base capacity resources beginning June 1, 2018, in accordance with predetermined unit specific parameter limits. The unit specific parameter limits for capacity performance and base capacity resources are based on default minimum operating parameter limits posted by PJM by technology type, and any adjustments based on a unit specific review process. These default parameters were based on analysis by the MMU.

Beginning June 1, 2018, all RPM procured capacity resources were either capacity performance or base capacity resources. Entities that elected the fixed resource requirement (FRR) option were allowed to procure the legacy annual capacity product for the 2018/2019 Delivery Year. Beginning June 1, 2019, all capacity resources, including resources in FRR capacity plans, will be either capacity performance or base capacity resources. The PJM tariff specifies that all generation capacity resources, regardless of the current commitment status, are subject to parameter limits on their cost-based offers. However, the tariff currently does not make it clear what parameter limit values are applicable for resources without a capacity commitment. The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance and base capacity resources.

Unit Specific Adjustment Process

Market participants can request an adjustment to the default values of parameter limits for capacity performance and base capacity resources, by submitting supporting documentation, which is reviewed by PJM and the MMU. The default minimum operating parameter limits or approved adjusted values are used by capacity performance resources and base capacity 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 a best practices 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.

Only certain technology types are subject to limits on operating parameters in their parameter limited schedules.[26] Solar units, wind units, run of river hydro units, and nuclear units are currently not subject to parameter limits. The MMU analyzed, for the units that are subject to parameter limits, the proportion of units that use the default limits published by PJM and the proportion of units that have been provided unit specific adjustments for some of the parameters. Table 3-16 shows, for the delivery year beginning June 1, 2019, the number of units that submitted and were approved unit specific parameter limit adjustments, and the number of units that used the default

26 For the default parameter limits by technology type, see PJM. "Unit-Specific Minimum Operating Parameters for Capacity Performance and Base Capacity Resources," which can be accessed at <https://www.pjm.com/~/media/committees-groups/committees/elc/postings/20150612-june-2015-capacity-performance-parameter-limitations-informational-posting.ashx>.

parameter limits published by PJM. Table 3-16 shows that 77.5 percent of subcritical coal steam units and 89.1 percent of supercritical coal steam units requested an adjustment to one or more parameter limits from the default limits published by PJM, while only 34.2 percent of combined cycle units, and 35.4 percent of frame combustion turbine units, and 18.9 percent of aero derivative combustion turbine units requested an adjustment to one or more parameter limits from the default limits published by PJM.

Table 3-16 Adjusted unit specific parameter limit statistics: Delivery Year 2019/2020

Technology Classification	Units Using Default Parameter Limits	Units with One or More Adjusted Parameter Limits	Percentage of Units with One or More Adjusted Parameter Limits
Aero CT	137	32	18.9%
Frame CT	190	104	35.4%
Combined Cycle	73	38	34.2%
Reciprocating Internal Combustion Engines	70	3	4.1%
Solid Fuel NUG	43	5	10.4%
Oil and Gas Steam	13	18	58.1%
Subcritical coal steam	20	69	77.5%
Supercritical coal steam	5	41	89.1%
Pumped Storage	10	0	0.0%

Real-Time Values

The MMU previously recommended that PJM market rules recognize the difference between operational parameters that indicate to PJM operators what a unit is capable of during the operating day and the parameters that result in uplift payments. The parameters provided to PJM operators each day should reflect what units are physically capable of so that operators can operate the system. 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. PJM implemented the real-time value variable in Markets Gateway to address this.

PJM market rules allow generators to communicate a resource's current operational capabilities to PJM when a resource cannot operate according to the unit specific parameters. These values are called real-time values (RTVs). The real-time values submittal process is not specified in the PJM Operating Agreement. The process is defined in PJM Manual 11. Unlike parameter exceptions, the use of real-time values makes a unit ineligible for make whole payments, unless the market seller can justify such operation based on an actual constraint.[27]

In practice, real-time values are generally used to communicate lower Turn Down Ratios which result from reduced Economic Max MW due to a derate (partial outage) on a unit, or from a requirement to operate at a defined output for equipment tests, environmental tests, or inspections. The RTV functionality allows units to communicate accurate short term operational parameters to PJM without requiring PJM customers to pay additional uplift charges, if the unit operates out of the money for routine tests and inspections. However, using real-time values to extend the time to start parameters (startup times and notification times) is inconsistent with the goal of real-time values. The protection offered by making units ineligible for uplift is only effective if the unit is committed and operated out of the money because of the RTVs. In the case of the notification time parameter or start time parameter, a longer real-time value decreases the likelihood of the unit being committed at all and may prohibit unit commitment in real time, making the RTV a mechanism for withholding.

The use of real-time values to extend startup times and notification times allows generators to circumvent the parameter limited schedule rules, to avoid commitment by PJM. Using RTVs to remove a unit from the real-time look-ahead dispatch window, and avoid commitment is withholding. These concerns are exacerbated if these units can otherwise provide relief to transmission constraints, and can provide flexibility to meet peak demand conditions. Currently, a resource that is staffed or has remote start capability and offers according to its physical capability, and a resource that makes the economic choice not to staff or invest in remote start and offers to decrease

27 See PJM Operating Agreement, Schedule 1, Section 3.2.3 (e).

the likelihood of commitment, are treated as identical in the capacity market. If a market seller makes an economic decision to not staff the unit or to not have remote start capability, and uses real-time values to communicate the longer time to start to PJM, there is currently no consequence to the market seller.

The MMU recommends that PJM institute rules to assess a penalty for resources that choose to submit real-time values that are less flexible than their unit specific parameter limits or approved parameter limit exceptions based on tariff defined justifications.

Generator Flexibility Incentives under Capacity Performance

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.[28] The Commission directed that capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.[29] The Commission directed PJM to submit tariff language to establish a process through which capacity performance resources that operate outside the defined unit-specific parameter limits can justify such operation and therefore remain eligible for make whole payments.[30]

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 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, who may be affiliates or have market power. 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. 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 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

28 151 FERC ¶ 61,208 at P 437 (2015) (June 9th Order).
29 *Id* at P 439.
30 *Id* at P 440.

to be scheduled and running during high demand conditions anyway, while the flexible CTs that are used as peaking plants would still have the incentive to follow LMP and dispatch instructions. CCs would also have the capability to be as flexible as the reference resource. These units will be exempt from nonperformance charges and made whole as long as they perform in accordance with their parameters. This ensures that all the peaking units that are needed by PJM for flexible operation do not self schedule at their maximum output, and follow PJM dispatch instructions during high demand conditions. If any of the less flexible resources need to be dispatched down by PJM for reliability reasons, they would be exempt from nonperformance charges.

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

The June 9th Order pointed out that the way to ensure that a resource's parameters are exposed to market consequences is to not allow any parameter limitations as an excuse for nonperformance. The same logic should apply to energy market uplift rules. A resource's parameters should be exposed to market consequences and the resource should not be made whole if it is operating less flexibly than the reference resource. Paying energy market uplift on the basis of parameters consistent with the flexibility goals of the capacity performance construct would ensure that performance incentives are consistent across the capacity and energy markets and ensure that performance risk is appropriately assigned to generation owners.

Parameter Impacts of Gas Pipeline Conditions

During extreme cold weather conditions, a number of gas fired generators request temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters affected include notification time, 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 leads to requests for 24 hour minimum run times and turn down ratios close to 1.0, to avoid deviations from the hourly nominated quantity.

Key parameters like startup and notification time were not included in the PLS matrix in 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.

The MMU observed instances when generators submitted temporary parameter exceptions based on claimed pipeline constraints even though these constraints are based on the nature of the transportation service that the generator procured from the pipeline. In some instances, generators requested temporary exceptions based on ratable take requirements stated in pipeline tariffs, even though the requirement is not enforced by the pipelines on a routine basis. If a unit were to be dispatched uneconomically using the inflexible parameters, the unit would receive make whole payments based on these temporary exceptions. The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced or on inferior transportation service procured by the generator.

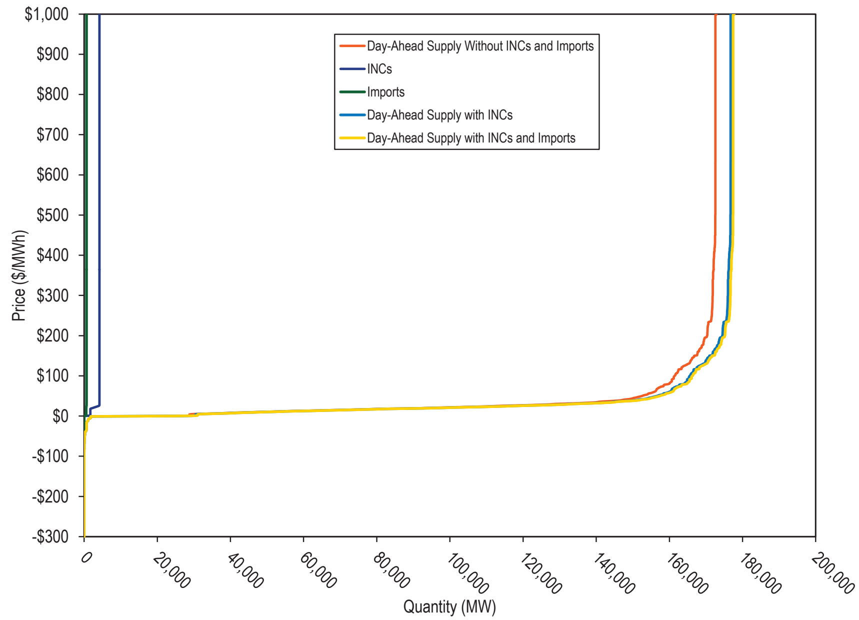
Virtual Offers and Bids

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.[31] Up to congestion transactions may be submitted between any two buses on a list of 49 buses, eligible for up to congestion transaction bidding.[32] 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 3-17 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 2019.

Figure 3-17 Day-ahead aggregate supply curves: 2019 example day



31 162 FERC ¶ 61,139 (2018).
32 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 3-18 shows example PJM day-ahead aggregate supply curves for the typical dispatch price range.

Figure 3-18 Typical dispatch price range for day-ahead aggregate supply curves: 2019 example day

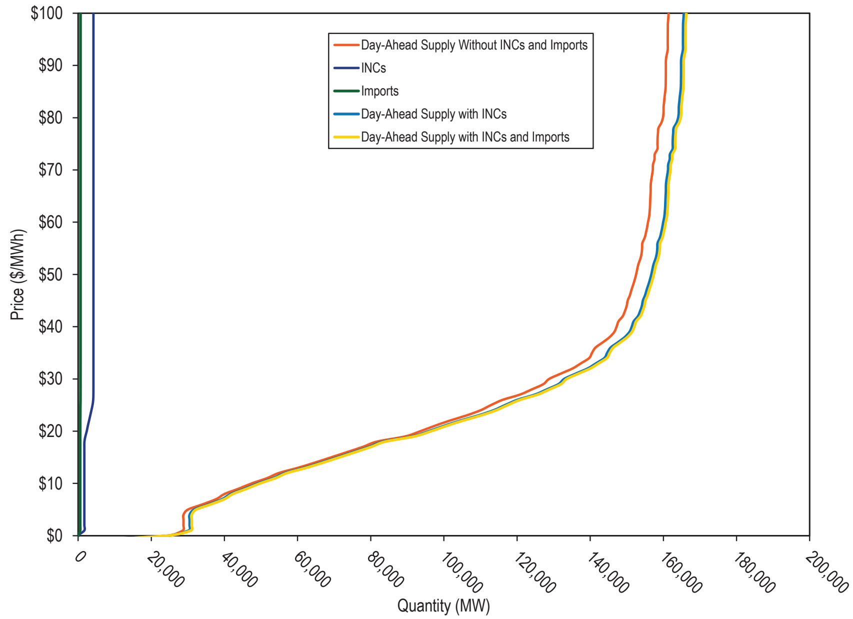


Table 3-17 shows the hourly average number of cleared and submitted increment offers and decrement bids by month in January 2018 through September 2019. The hourly average submitted and cleared increment MW increased by 11.5 percent and 11.6 percent, from 5,725 MW and 2,568 MW in the first nine months of 2018 to 6,382 MW and 2,866 MW in the first nine months of 2019. The hourly average submitted and cleared decrement MW increased by 6.4 percent and 39.7 percent, from 6,854 MW and 2,841 MW in the first nine months of 2018 to 7,293 MW and 3,970 MW in the first nine months of 2019.

Table 3-17 Average hourly number of cleared and submitted INCs and DECs by month: January 2018 through September 2019

		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
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	2,791	5,986	521	1,267	2,580	7,019	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	Oct	3,230	6,328	281	1,021	3,106	6,714	162	788
2018	Nov	3,258	5,980	287	958	3,020	6,416	154	817
2018	Dec	2,428	5,293	242	951	3,080	6,008	169	736
2018	Annual	2,676	5,776	245	919	2,906	6,753	176	762
2019	Jan	2,934	6,777	282	1,122	3,856	7,149	215	834
2019	Feb	2,895	5,776	260	1,029	3,441	6,115	197	781
2019	Mar	2,973	5,961	268	1,057	3,319	6,830	181	859
2019	Apr	3,048	6,008	286	1,060	3,104	6,226	154	733
2019	May	3,107	6,468	273	1,082	4,236	6,903	178	726
2019	Jun	2,892	6,363	226	977	4,408	7,245	226	863
2019	Jul	2,655	6,712	202	1,051	4,544	9,223	251	1,086
2019	Aug	2,577	6,573	220	1,100	3,744	7,056	217	860
2019	Sep	2,715	6,737	221	972	5,046	8,790	255	900
2019	Jan-Sep	2,866	6,382	249	1,051	3,970	7,293	208	850

Table 3-18 shows the average hourly number of up to congestion transactions and the average hourly MW in January 2018 through September 2019. In the first nine months of 2019, the average hourly submitted and cleared up to congestion MW increased by 5.8 percent and 15.9 percent, compared to the first nine months of 2018.

Table 3-18 Average hourly cleared and submitted up to congestion bids by month: January 2018 through September 2019

		Up to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
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	Oct	16,284	49,862	939	2,115
2018	Nov	18,027	58,069	1,035	2,173
2018	Dec	18,446	55,795	1,152	2,254
2018	Annual	17,624	58,650	1,117	2,691
2019	Jan	20,624	65,533	1,219	2,489
2019	Feb	21,341	66,240	1,005	2,013
2019	Mar	23,205	75,760	1,045	2,144
2019	Apr	21,323	63,388	872	1,669
2019	May	19,407	59,684	862	1,713
2019	Jun	18,598	51,678	1,021	1,953
2019	Jul	19,197	56,161	1,128	2,265
2019	Aug	20,247	58,841	1,254	2,550
2019	Sep	20,005	74,494	1,136	2,523
2019	Jan-Sep	20,433	63,503	1,061	2,149

Table 3-19 shows the average hourly number of import and export transactions and the average hourly MW in January 2018 through September 2019. In the first nine months of 2019, the average hourly submitted and cleared import transaction MW increased by 30.9 and 25.7 percent, and the average hourly submitted and cleared export transaction MW increased by 13.3 and 13.6 percent, compared to the first nine months of 2018.

Table 3-19 Hourly average day-ahead number of cleared and submitted import and export transactions by month: January 2018 through September 2019

		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
2018	Jan	541	640	8	10	2,531	2,566	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	286	4	5	3,014	3,027	15	15
2018	Aug	358	388	4	5	3,647	3,671	17	17
2018	Sep	230	244	4	4	3,384	3,390	17	17
2018	Oct	362	371	4	5	3,387	3,432	18	18
2018	Nov	501	533	7	7	2,037	1,992	13	13
2018	Dec	453	518	7	8	3,030	3,035	18	18
2018	Annual	412	462	6	7	2,797	2,814	15	15
2019	Jan	545	653	7	9	3,569	3,593	22	22
2019	Feb	564	671	6	8	3,169	3,182	17	18
2019	Mar	387	449	5	7	2,675	2,686	15	15
2019	Apr	255	288	4	5	2,483	2,496	15	15
2019	May	279	298	3	4	2,426	2,458	15	15
2019	Jun	291	308	3	4	2,790	2,806	17	17
2019	Jul	283	311	4	5	3,075	3,106	15	15
2019	Aug	277	303	3	4	2,907	2,923	16	16
2019	Sep	162	177	3	3	3,163	3,193	17	17
2019	Jan-Sep	505	598	6	8	3,154	3,171	18	18

Table 3-20 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 in January 2018 through September 2019.

Table 3-20 Type of day-ahead marginal resources: January 2018 through September 2019

	2018						2019					
	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	5.3%	0.1%	82.5%	7.4%	4.6%	0.0%	13.4%	0.3%	59.1%	17.4%	9.9%	0.0%
Feb	5.9%	0.1%	80.8%	9.1%	4.0%	0.0%	11.7%	0.1%	60.0%	15.4%	12.8%	0.0%
Mar	17.2%	0.2%	47.0%	20.4%	15.2%	0.0%	9.3%	0.1%	60.5%	17.0%	13.1%	0.0%
Apr	13.5%	0.1%	45.7%	24.1%	16.6%	0.0%	8.3%	0.1%	64.9%	14.8%	11.9%	0.0%
May	15.2%	0.1%	49.6%	24.0%	11.1%	0.0%	9.9%	0.1%	53.1%	21.0%	15.9%	0.0%
Jun	15.3%	0.1%	54.5%	20.8%	9.3%	0.0%	10.5%	0.0%	49.0%	23.7%	16.8%	0.0%
Jul	12.4%	0.1%	57.8%	19.0%	10.6%	0.1%	9.1%	0.0%	51.5%	26.0%	13.4%	0.0%
Aug	11.1%	0.2%	54.5%	22.5%	11.7%	0.0%	13.0%	0.1%	63.1%	14.1%	9.6%	0.0%
Sep	15.1%	0.2%	50.7%	20.5%	13.5%	0.0%	14.0%	0.1%	60.5%	13.4%	12.0%	0.0%
Oct	12.7%	0.2%	54.3%	19.7%	13.0%	0.0%						
Nov	10.2%	0.1%	56.1%	20.3%	13.2%	0.0%						
Dec	12.1%	0.1%	58.3%	20.4%	9.1%	0.0%						
Annual	10.9%	0.1%	62.3%	16.9%	9.8%	0.0%	10.9%	0.1%	57.7%	18.4%	12.9%	0.0%

Figure 3-19 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month from January 2005 through September 2019.

Figure 3-19 Monthly bid and cleared INCs, DECs and UTCs (MW): January 2005 through September 2019

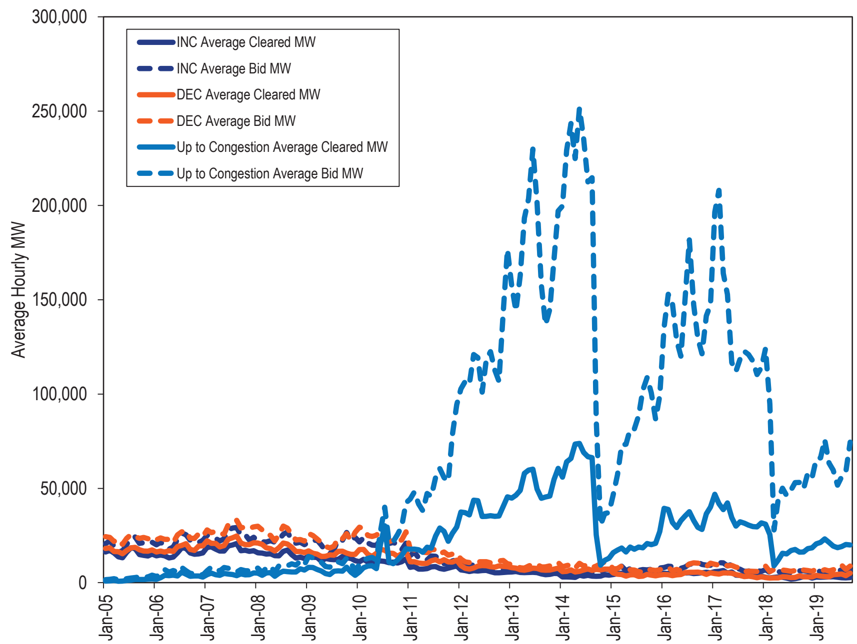
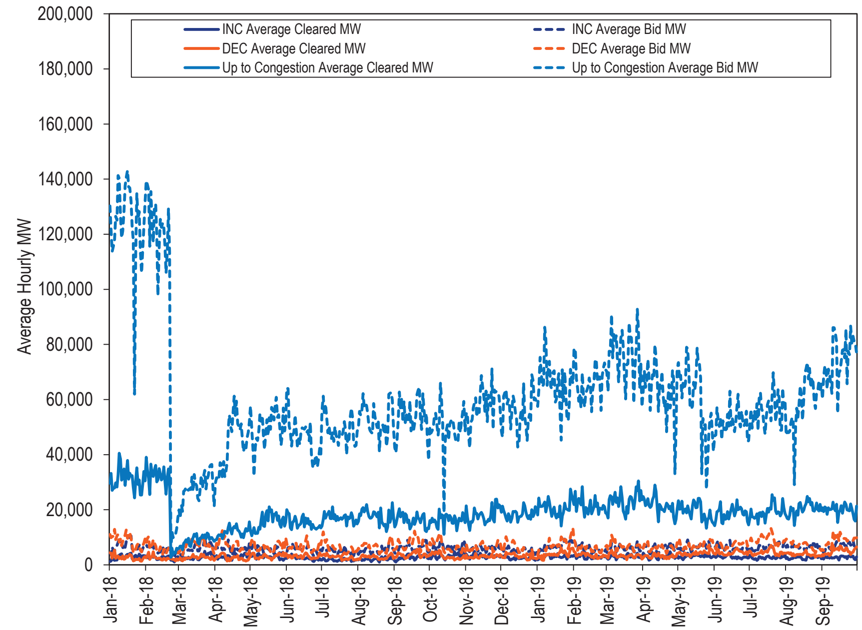


Figure 3-20 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 1, 2018 through September 30, 2019.

Figure 3-20 Daily bid and cleared INCs, DECs, and UTCs (MW): January 2018 through September 2019



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 3-21 shows, in the first nine months of 2018 and 2019, the total increment offers and decrement bids and cleared MW by type of parent organization.

Table 3-21 INC and DEC bids and cleared MWh by type of parent organization (MWh): January through September, 2018 and 2019

	2018 (Jan-Sep)				2019 (Jan-Sep)			
Category	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	73,391,780	88.7%	29,636,599	83.3%	76,220,253	85.1%	37,111,117	82.9%
Physical	9,311,371	11.3%	5,926,016	16.7%	13,365,499	14.9%	7,670,318	17.1%
Total	82,703,152	100.0%	35,562,615	100.0%	89,585,752	100.0%	44,781,434	100.0%

Table 3-22 shows, in the first nine months of 2018 and 2019, the total up to congestion bids and cleared MWh by type of parent organization.

Table 3-22 Up to congestion transactions by type of parent organization (MWh): January through September, 2018 and 2019

	2018 (Jan-Sep)				2019 (Jan-Sep)			
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	387,384,301	98.5%	111,150,309	96.2%	408,325,274	98.2%	128,203,350	95.8%
Physical	5,911,253	1.5%	4,401,790	3.8%	7,684,296	1.8%	5,654,374	4.2%
Total	393,295,554	100.0%	115,552,099	100.0%	416,009,570	100.0%	133,857,724	100.0%

Table 3-23 shows, in the first nine months of 2018 and 2019, the total import and export transactions by whether the parent organization was financial or physical.

Table 3-23 Import and export transactions by type of parent organization (MW): January through September, 2018 and 2019

		2018 (Jan-Sep)		2019 (Jan-Sep)	
	Category	Total Import and Export MW	Percent	Total Import and Export MW	Percent
Day-Ahead	Financial	4,882,989	26.5%	5,153,149	27.3%
	Physical	13,561,188	73.5%	13,755,585	72.7%
	Total	18,444,177	100.0%	18,908,733	100.0%
Real-Time	Financial	8,193,181	21.1%	8,634,158	23.7%
	Physical	30,569,553	78.9%	27,730,465	76.3%
	Total	38,762,734	100.0%	36,364,623	100.0%

Table 3-24 shows increment offers and decrement bids by top 10 locations in the first nine months of 2018 and 2019.

Table 3-24 Virtual offers and bids by top 10 locations (MW): January through September, 2018 and 2019

2018 (Jan-Sep)					2019 (Jan-Sep)				
Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	2,239,066	1,063,197	3,302,263	MISO	INTERFACE	92,458	5,480,231	5,572,690
MISO	INTERFACE	163,594	1,552,703	1,716,297	WESTERN HUB	HUB	974,342	1,456,731	2,431,073
SOUTHIMP	INTERFACE	1,637,486	0	1,637,486	AEP-DAYTON HUB	HUB	431,099	771,311	1,202,410
LINDENVFT	INTERFACE	25,426	842,895	868,321	LINDENVFT	INTERFACE	27,083	1,164,030	1,191,114
DOM_RESID_AGG	RESIDUAL_METERED_EDC	109,126	681,083	790,209	DOM_RESID_AGG	RESIDUAL_METERED_EDC	196,888	932,152	1,129,040
NYIS	INTERFACE	579,955	152,743	732,698	DOMINION HUB	HUB	460,460	581,642	1,042,102
BGE_RESID_AGG	RESIDUAL_METERED_EDC	109,757	603,047	712,804	SOUTHIMP	INTERFACE	958,877	0	958,877
N ILLINOIS HUB	HUB	238,444	438,345	676,790	N ILLINOIS HUB	HUB	428,538	521,707	950,245
DOMINION HUB	HUB	100,779	541,778	642,556	BGE_RESID_AGG	RESIDUAL_METERED_EDC	184,216	692,349	876,565
AEP-DAYTON HUB	HUB	232,250	372,813	605,063	NYIS	INTERFACE	571,531	200,621	772,153
Top ten total		5,435,883	6,248,603	11,684,486			4,325,493	11,800,775	16,126,267
PJM total		16,884,534	18,678,081	35,562,615			18,774,506	26,006,928	44,781,434
Top ten total as percent of PJM total		32.2%	33.5%	32.9%			23.0%	45.4%	36.0%

Table 3-25 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 2018 and 2019.[33]

Table 3-25 Cleared up to congestion import bids by top 10 source and sink pairs (MW): January through September, 2018 and 2019

2018 (Jan-Sep)							
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
NORTHWEST	INTERFACE	COMED_RESID_AGG	AGGREGATE	1,169,773	$1,074,659	($875,604)	$199,056
OVEC	INTERFACE	DEOK_RESID_AGG	AGGREGATE	1,005,813	$395,063	($195,040)	$200,023
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	AEP GEN HUB	HUB	656,638	$559,109	($597,118)	($38,009)
MISO	INTERFACE	CHICAGO HUB	HUB	627,608	$367,775	$84,105	$451,879
OVEC	INTERFACE	ATSI GEN HUB	HUB	505,828	$239,895	($199,770)	$40,125
MISO	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	497,570	$290,960	($39,112)	$251,848
Top ten total				10,528,487	$5,008,819	($1,220,220)	$3,788,599
PJM total				25,017,329	$8,696,255	($1,399,087)	$7,297,167
Top ten total as percent of PJM total				42.1%	57.6%	87.2%	51.9%
2019 (Jan-Sep)							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	3,672,891	$2,624,342	($1,008,392)	$1,615,950
NORTHWEST	INTERFACE	CHICAGO GEN HUB	HUB	2,267,861	$1,168,166	($602,967)	$565,200
NORTHWEST	INTERFACE	COMED_RESID_AGG	AGGREGATE	2,118,015	$1,937,641	($1,056,650)	$880,991
NYIS	INTERFACE	RECO_RESID_AGG	AGGREGATE	1,430,149	($484,469)	$675,323	$190,854
MISO	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	1,214,494	$169,568	$530,215	$699,783
NEPTUNE	INTERFACE	JCPL_RESID_AGG	AGGREGATE	1,017,897	$247,481	($164,126)	$83,355
NORTHWEST	INTERFACE	CHICAGO HUB	HUB	903,699	$483,274	($96,332)	$386,942
SOUTHIMP	INTERFACE	AEP GEN HUB	HUB	758,037	$1,224,095	($730,682)	$493,413
SOUTHIMP	INTERFACE	AEPAPCO_RESID_AGG	AGGREGATE	671,711	$471,888	($115,309)	$356,579
NORTHWEST	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	537,544	$471,504	($22,757)	$448,746
Top ten total				14,592,297	$8,313,490	($2,591,677)	$5,721,814
PJM total				28,290,352	$16,511,901	($6,245,518)	$10,266,384
Top ten total as percent of PJM total				51.6%	50.3%	41.5%	55.7%

33 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 3-26 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 2018 and 2019.

Table 3-26 Cleared up to congestion export bids by top 10 source and sink pairs (MW): January through September, 2018 and 2019

				2018 (Jan-Sep)			
				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	548,284	$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
OVEC	ZONE	SOUTHEXP	INTERFACE	143,241	$156,894	($91,374)	$65,520
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
112 WILTON	EHVAGG	NIPSCO	INTERFACE	108,254	($107,221)	$146,103	$38,882
Top ten total				2,970,741	$2,623,422	$1,333,668	$3,957,090
PJM total				9,622,817	($3,121,469)	$7,175,533	$4,054,064
Top ten total as percent of PJM total				30.9%	(84.0%)	18.6%	97.6%
				2019 (Jan-Sep)			
				Exports			
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
COMED_RESID_AGG	AGGREGATE	NIPSCO	INTERFACE	1,846,088	$1,383,522	$869,684	$2,253,206
N ILLINOIS HUB	HUB	NIPSCO	INTERFACE	1,618,617	$1,088,917	($348,429)	$740,488
CHICAGO GEN HUB	HUB	NIPSCO	INTERFACE	1,405,388	$278,839	$679,091	$957,930
CHICAGO HUB	HUB	NIPSCO	INTERFACE	1,063,992	$978,025	$366,039	$1,344,064
CHICAGO HUB	HUB	MISO	INTERFACE	739,298	$211,933	($148,459)	$63,474
AEP GEN HUB	HUB	SOUTHEXP	INTERFACE	711,021	($951,226)	$1,885,040	$933,814
CHICAGO GEN HUB	HUB	MISO	INTERFACE	518,556	$41,936	$37,577	$79,513
N ILLINOIS HUB	HUB	MISO	INTERFACE	490,740	$82,582	($144,049)	($61,467)
N ILLINOIS HUB	HUB	SOUTHEXP	INTERFACE	486,524	($29,001)	$200,765	$171,764
CHICAGO GEN HUB	HUB	NORTHWEST	INTERFACE	396,963	($433,776)	$555,526	$121,750
Top ten total				9,277,187	$2,651,751	$3,952,784	$6,604,535
PJM total				15,943,796	($247,518)	$10,144,990	$9,897,473
Top ten total as percent of PJM total				58.2%	(1071.3%)	39.0%	66.7%

Table 3-27 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 2018 and 2019.

Table 3-27 Cleared up to congestion wheel bids by top 10 source and sink pairs (MW): January through September, 2018 and 2019

2018 (Jan-Sep)							
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
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	253,579	$42,045	$431,202	$473,248
SOUTHIMP	INTERFACE	OVEC	INTERFACE	218,305	($1,235,838)	$1,167,990	($67,848)
SOUTHIMP	INTERFACE	NIPSCO	INTERFACE	176,893	($581,953)	$841,593	$259,640
OVEC	INTERFACE	SOUTHEXP	INTERFACE	158,012	$289,778	($220,284)	$69,494
MISO	INTERFACE	OVEC	INTERFACE	148,690	$66,484	($83,633)	($17,149)
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	143,660	$558,551	$31,300	$589,850
MISO	INTERFACE	SOUTHEXP	INTERFACE	131,717	$254,943	($120,606)	$134,338
Top ten total				3,487,425	$1,955,808	$1,918,187	$3,873,996
PJM total				4,774,729	$1,614,703	$1,876,453	$3,491,156
Top ten total as percent of PJM total				73.0%	121.1%	102.2%	111.0%
2019 (Jan-Sep)							
Wheels							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	1,781,084	$1,130,395	$53,205	$1,183,599
MISO	INTERFACE	NIPSCO	INTERFACE	1,758,144	$1,645,884	($194,491)	$1,451,394
MISO	INTERFACE	SOUTHEXP	INTERFACE	889,111	($959,623)	$3,152,146	$2,192,524
NORTHWEST	INTERFACE	MISO	INTERFACE	869,753	$837,161	($470,939)	$366,222
MISO	INTERFACE	NORTHWEST	INTERFACE	581,756	$274,179	$64,171	$338,350
SOUTHIMP	INTERFACE	MISO	INTERFACE	354,465	$454,176	($261,645)	$192,531
SOUTHIMP	INTERFACE	NIPSCO	INTERFACE	297,721	$230,377	$556,152	$786,529
NORTHWEST	INTERFACE	SOUTHEXP	INTERFACE	262,102	$456,506	($146,641)	$309,865
LINDENVFT	INTERFACE	HUDSONTP	INTERFACE	194,779	$94,362	($42,611)	$51,751
IMO	INTERFACE	SOUTHEXP	INTERFACE	184,970	$10,997	$517,445	$528,443
Top ten total				7,173,885	$4,174,415	$3,226,792	$7,401,208
PJM total				8,420,422	$4,306,298	$2,939,003	$7,245,301
Top ten total as percent of PJM total				85.2%	96.9%	109.8%	102.2%

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 16.5 percent of the PJM total internal up to congestion transactions MW in the first nine months of 2019.

Table 3-28 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 2018 and 2019. The total internal UTC profits decreased by $10.8 million, from $16.4 million in the first nine months of 2018 to $5.5 million in the first nine months of 2019. The total internal cleared MW increased by 5.1 million MW, or 6.7 percent, from 76.1 million MW in the first nine months of 2018 to 81.2 million MW in the first nine months of 2019.

Table 3-28 Cleared up to congestion internal bids by top 10 source and sink pairs (MW): January through September, 2018 and 2019

2018 (Jan-Sep)							
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	623,342	($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	456,014	$847,488	($1,210,388)	($362,900)
Top ten total				6,891,061	$4,731,599	($3,831,440)	$900,160
PJM total				76,137,224	($13,137,136)	$29,517,862	$16,380,726
Top ten total as percent of PJM total				9.1%	(36.0%)	(13.0%)	5.5%
2019 (Jan-Sep)							
Internal							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
OVEC_RESID_AGG	AGGREGATE	DEOK_RESID_AGG	AGGREGATE	1,987,576	$56,715	($350,761)	($294,047)
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	1,710,830	$1,190,773	($624,876)	$565,897
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	1,688,489	$18,599	$313,596	$332,194
OVEC_RESID_AGG	AGGREGATE	DAY_RESID_AGG	AGGREGATE	1,534,526	$127,249	($43,063)	$84,185
AEP GEN HUB	HUB	AEP-DAYTON HUB	HUB	1,353,911	$578,741	($433,479)	$145,263
AEP GEN HUB	HUB	FEOHIO_RESID_AGG	AGGREGATE	1,251,621	$674,656	($693,980)	($19,324)
N ILLINOIS HUB	HUB	CHICAGO HUB	HUB	1,013,611	($245,478)	$367,797	$122,319
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	1,005,492	$764,059	($481,265)	$282,793
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	992,387	($9,936)	$464,675	$454,739
AECO_RESID_AGG	AGGREGATE	VINELAND_RESID_AGG	AGGREGATE	900,369	($583,798)	$104,069	($479,728)
Top ten total				13,438,811	$2,571,580	($1,377,287)	$1,194,292
PJM total				81,203,154	$19,532,927	($13,994,454)	$5,538,473
Top ten total as percent of PJM total				16.5%	13.2%	9.8%	21.6%

Table 3-29 shows the number of source-sink pairs that were offered and cleared monthly for January 1, 2018 through September 30, 2019.

Table 3-29 Number of offered and cleared source and sink pairs: January 2018 through September 2019

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
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	Oct	1,838	2,118	1,610	1,954
2018	Nov	1,539	1,922	1,371	1,689
2018	Dec	1,606	1,787	1,426	1,608
2018	Annual	2,456	2,899	1,955	2,365
2019	Jan	1,693	1,893	1,527	1,712
2019	Feb	1,701	1,881	1,496	1,733
2019	Mar	1,673	1,806	1,506	1,653
2019	Apr	1,555	1,806	1,395	1,653
2019	May	1,584	1,856	1,424	1,718
2019	Jun	1,770	1,970	1,601	1,797
2019	Jul	1,767	1,950	1,635	1,819
2019	Aug	1,880	2,034	1,690	1,879
2019	Sep	1,891	2,007	1,702	1,842
2019	Jan-Sep	1,689	1,860	1,510	1,699

Table 3-30 Cleared up to congestion transactions by type (MW): January through September, 2018 and 2019

	2018 (Jan-Sep)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	10,528,487	2,970,741	3,487,425	6,891,061	23,877,713
PJM total (MW)	25,017,329	9,622,817	4,774,729	76,137,224	115,552,099
Top ten total as percent of PJM total	42.1%	30.9%	73.0%	9.1%	20.7%
PJM total as percent of all up to congestion transactions	21.7%	8.3%	4.1%	65.9%	100.0%
	2019 (Jan-Sep)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	14,592,297	9,277,187	7,173,885	13,438,811	44,482,179
PJM total (MW)	28,290,352	15,943,796	8,420,422	81,203,154	133,857,724
Top ten total as percent of PJM total	51.6%	58.2%	85.2%	16.5%	33.2%
PJM total as percent of all up to congestion transactions	21.1%	11.9%	6.3%	60.7%	100.0%

Table 3-30 and Figure 3-21 show total cleared up to congestion transactions by type in the first nine months of 2018 and 2019. Total up to congestion transactions in the first nine months of 2019 increased by 15.8 percent from 115.6 million MW in the first nine months of 2018 to 133.9 million MW in the first nine months of 2019. Internal up to congestion transactions in the first nine months of 2019 were 60.7 percent of all up to congestion transactions compared to 65.9 percent in the first nine months of 2018.

Figure 3-21 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.[34] But in 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.[35] 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. UTC activity has increased, following that reduction.

34 Id.
35 162 FERC ¶ 61,139 (2018).

Figure 3-22 shows the daily cleared up to congestion MW by transaction type from January 1, 2018 through September 30, 2019.

Figure 3-21 Monthly cleared up to congestion transactions by type (MW): January 2005 through September 2019

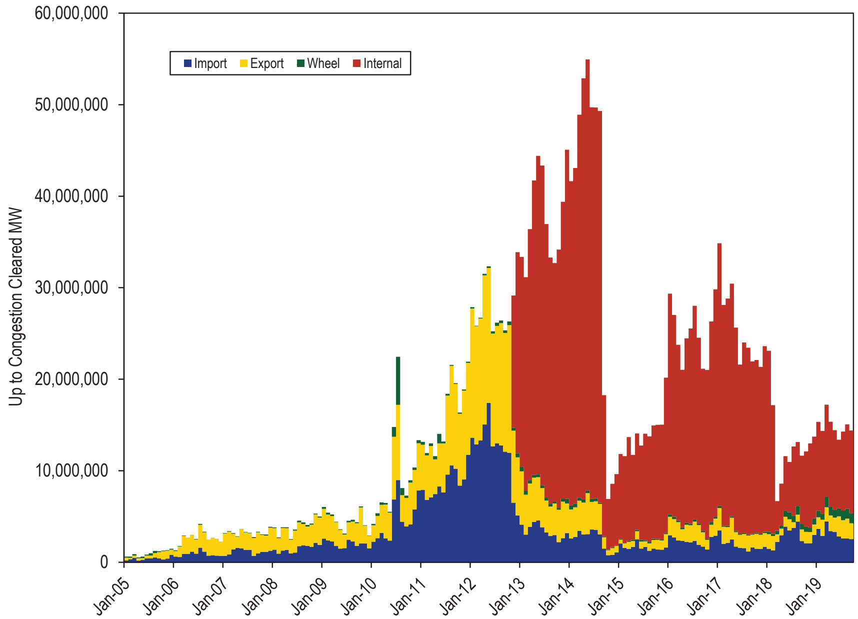
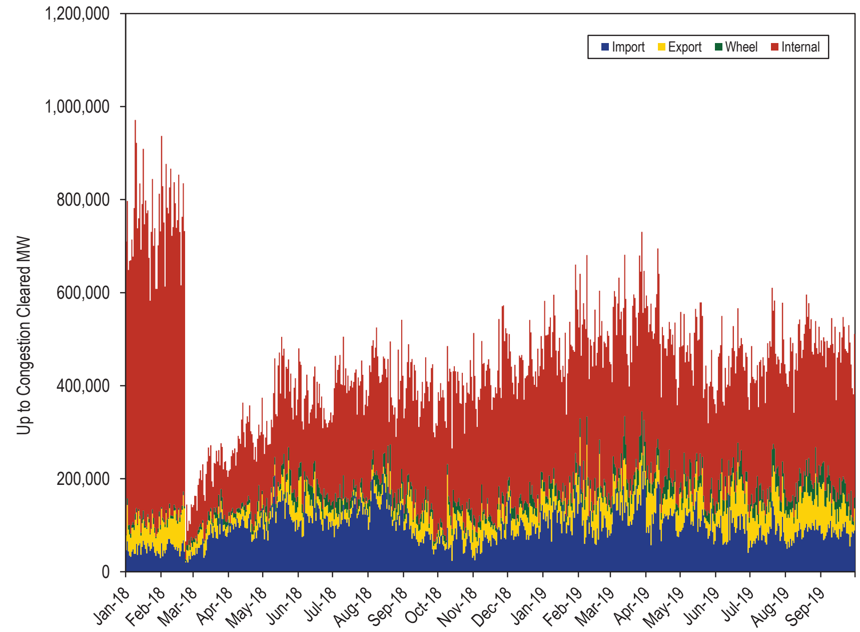


Figure 3-22 Daily cleared up to congestion transaction by type (MW): January 2018 through September 2019



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. In a competitive market, prices equal the short run marginal cost of the marginal unit of output and reflect the most efficient and least cost allocation of resources to meet demand.

LMP

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 or influence prices through manual interventions such as load biasing, changing constraint limits and penalty factors, and committing reserves beyond the requirement.

Real-time and day-ahead energy market load-weighted prices were 30.0 percent and 28.4 percent lower in the first nine months of 2019 than in the first nine months of 2018.

PJM real-time energy market prices decreased in the first nine months of 2019 compared to the first nine months of 2018. The average LMP was 28.0 percent lower in the first nine months of 2019 than in the first nine months of 2018, $26.30 per MWh versus $36.52 per MWh. The load-weighted average real-time LMP was 30.0 percent lower in the first nine months of 2019 than in the first nine months of 2018, $27.60 per MWh versus $39.43 per MWh.

The real-time load-weighted average LMP for the first nine months of 2019 was 12.8 percent lower than the real-time fuel-cost adjusted, load-weighted, average LMP for the first nine months of 2019. If fuel and emission costs in the first nine months of 2019 had been the same as in the first nine months of 2018, holding everything else constant, the load-weighted LMP would have been higher, $31.65 per MWh instead of the observed $27.60 per MWh.

PJM day-ahead energy market prices decreased in the first nine months of 2019 compared to the first nine months of 2018. The day-ahead average LMP was 26.7 percent lower in the first nine months of 2019 than in the first nine months of 2018, $26.41 per MWh versus $36.04 per MWh. The day-ahead load-weighted average LMP was 28.4 percent lower in the first nine months of 2019 than in the first nine months of 2018, $27.70 per MWh versus $38.71 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 curve.[36] 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.[37]

LMP may, at times, be set by transmission penalty factors, which exceed $1,000 per MWh. 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

36 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.

37 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).

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

Real-Time Average LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[38]

PJM Real-Time, Average LMP

Table 3-31 shows the PJM real-time, average LMP for the first nine months of 1998 through 2019.[39]

Table 3-31 Real-time, average LMP (Dollars per MWh): January through September, 1998 through 2019

	Real-Time LMP			Year-to-Year Change		
Jan-Sep	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$23.18	$16.86	$36.00	NA	NA	NA
1999	$31.65	$18.77	$83.28	36.6%	11.3%	131.3%
2000	$25.88	$18.22	$23.70	(18.2%)	(2.9%)	(71.5%)
2001	$36.00	$25.48	$51.30	39.1%	39.9%	116.4%
2002	$28.13	$20.70	$23.92	(21.9%)	(18.8%)	(53.4%)
2003	$40.42	$33.68	$26.00	43.7%	62.7%	8.7%
2004	$43.85	$39.99	$21.82	8.5%	18.7%	(16.1%)
2005	$54.69	$44.53	$33.67	24.7%	11.4%	54.3%
2006	$51.79	$43.50	$34.93	(5.3%)	(2.3%)	3.7%
2007	$57.34	$49.40	$35.52	10.7%	13.6%	1.7%
2008	$71.94	$61.33	$41.64	25.4%	24.2%	17.2%
2009	$37.42	$33.00	$17.92	(48.0%)	(46.2%)	(57.0%)
2010	$46.13	$37.89	$26.99	23.3%	14.8%	50.6%
2011	$45.79	$37.05	$32.25	(0.7%)	(2.2%)	19.5%
2012	$32.45	$28.78	$21.94	(29.1%)	(22.3%)	(32.0%)
2013	$37.30	$32.44	$22.84	15.0%	12.7%	4.1%
2014	$52.72	$36.06	$74.17	41.3%	11.2%	224.8%
2015	$35.96	$27.88	$30.75	(31.8%)	(22.7%)	(58.5%)
2016	$27.43	$23.61	$15.73	(23.7%)	(15.3%)	(48.8%)
2017	$28.79	$25.28	$16.81	5.0%	7.1%	6.9%
2018	$36.52	$27.26	$33.22	26.8%	7.8%	97.6%
2019	$26.30	$23.39	$17.69	(28.0%)	(14.2%)	(46.8%)

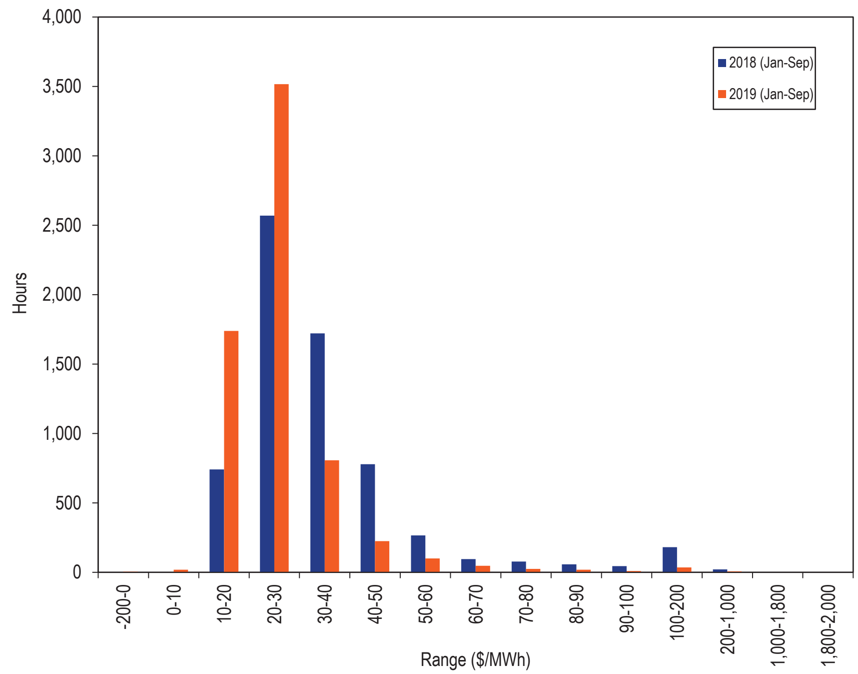
38 See the 2010 State of the Market Report for PJM: Technical Reference for PJM Markets, at "Calculating Locational Marginal Price," p 16-18 for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

39 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 Average LMP Duration

Figure 3-23 shows the hourly distribution of PJM real-time average LMP for the first nine months of 2018 and 2019.

Figure 3-23 Average LMP for the Real-Time Energy Market: January through September, 2018 and 2019



Real-Time, Load-Weighted, Average LMP

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

PJM Real-Time, Load-Weighted, Average LMP

Table 3-32 shows the PJM real-time, load-weighted, average LMP in the first nine months of 1998 through 2019.

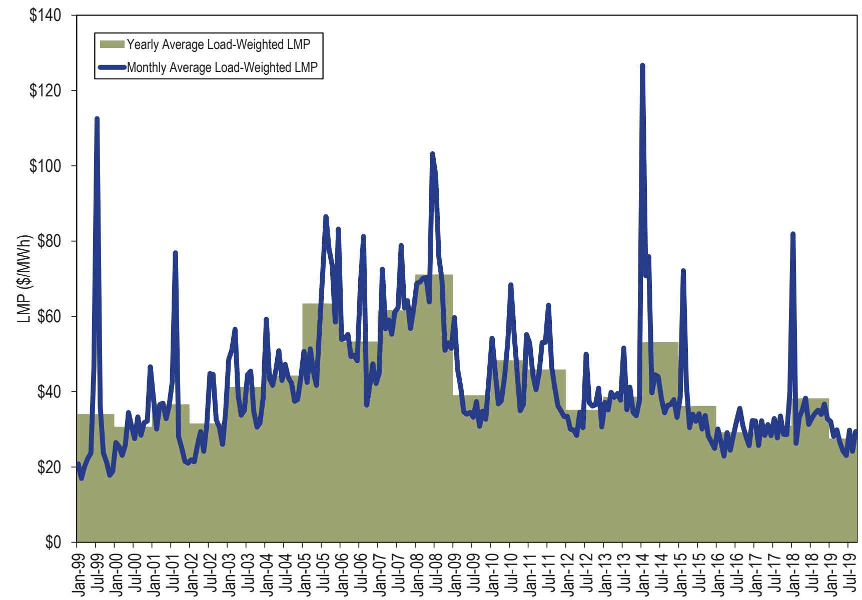
Table 3-32 Real-time, load-weighted, average LMP (Dollars per MWh): January through September, 1998 through 2019

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$26.06	$18.20	$44.65	NA	NA	NA
1999	$38.65	$20.02	$104.17	48.3%	10.0%	133.3%
2000	$28.49	$19.30	$26.89	(26.3%)	(3.6%)	(74.2%)
2001	$40.96	$28.18	$64.57	43.8%	46.0%	140.1%
2002	$31.95	$23.09	$29.14	(22.0%)	(18.1%)	(54.9%)
2003	$43.57	$38.17	$26.53	36.3%	65.3%	(9.0%)
2004	$46.44	$43.03	$21.89	6.6%	12.7%	(17.5%)
2005	$60.44	$50.10	$36.52	30.2%	16.4%	66.9%
2006	$56.39	$46.82	$40.70	(6.7%)	(6.5%)	11.4%
2007	$61.83	$55.12	$37.98	9.7%	17.7%	(6.7%)
2008	$77.27	$66.73	$43.80	25.0%	21.1%	15.3%
2009	$39.57	$34.57	$19.04	(48.8%)	(48.2%)	(56.5%)
2010	$49.91	$40.33	$29.65	26.2%	16.7%	55.7%
2011	$49.48	$38.72	$37.02	(0.9%)	(4.0%)	24.8%
2012	$35.02	$29.84	$25.44	(29.2%)	(22.9%)	(31.3%)
2013	$39.75	$33.61	$26.47	13.5%	12.6%	4.0%
2014	$58.60	$37.93	$86.22	47.4%	12.8%	225.8%
2015	$38.94	$29.09	$33.95	(33.5%)	(23.3%)	(60.6%)
2016	$29.32	$24.60	$17.13	(24.7%)	(15.4%)	(49.6%)
2017	$30.36	$26.26	$18.81	3.5%	6.7%	9.8%
2018	$39.43	$28.78	$36.82	29.9%	9.6%	95.7%
2019	$27.60	$24.23	$18.69	(30.0%)	(15.8%)	(49.2%)

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

Figure 3-24 shows the PJM real-time monthly and annual load-weighted LMP for January 1999 through September 2019.

Figure 3-24 Real-time, monthly and annual, load-weighted, average LMP: January 1999 through September 2019



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

Figure 3-25 shows the PJM real-time monthly load-weighted average LMP and inflation adjusted monthly load-weighted average LMP for 1998, through September 2019.[40] Table 3-33 shows the PJM real-time load-weighted average LMP and inflation adjusted, load-weighted average LMP for the first nine months of every year from 1998 through 2019. The PJM real-time inflation adjusted load-weighted average LMP for January through September, 2019

40 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 1, 2019)

was the lowest nine month value since PJM real-time markets started on April 1, 1999. The real-time inflation adjusted monthly load-weighted average LMP for June 2019 ($14.54 per MWh) was the lowest monthly value since April 1, 1999.

Figure 3-25 Real-time, monthly, load-weighted, average LMP unadjusted and adjusted for inflation: January 1998 through September 2019

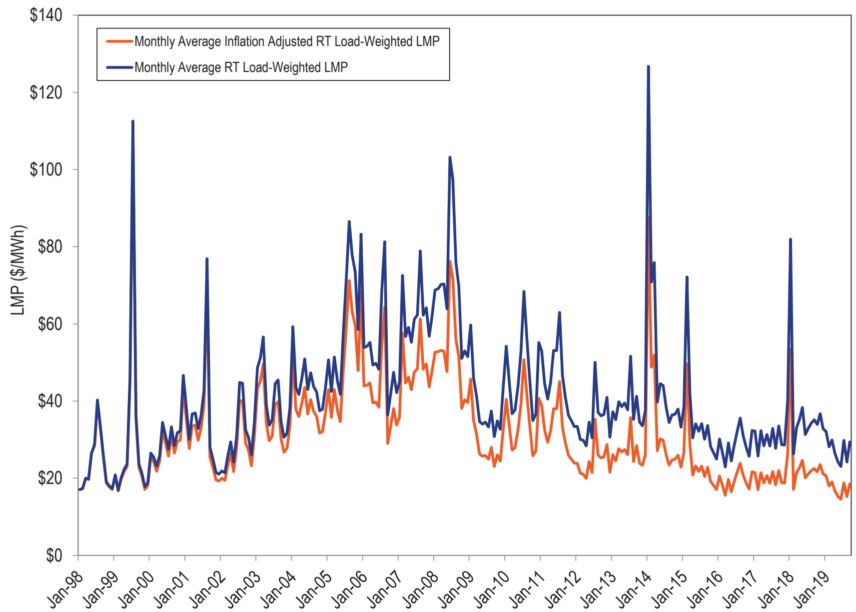


Table 3-33 Real-time, yearly, load-weighted, average LMP unadjusted and adjusted for inflation: January through September, 1998 through 2019

	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
2019	$27.60	$17.49

Real-Time Dispatch and Pricing

The PJM Real-Time Energy Market consists of a series of applications that produce the generator dispatch for energy and reserves, and five minute locational marginal prices (LMPs). These applications include the ancillary services optimizer (ASO), real-time security constrained economic dispatch (RT SCED), and the locational pricing calculator (LPC).[41] The final real-time LMPs and ancillary service clearing prices are determined for every five minute interval by LPC.

The processes to commit and dispatch reserves determine whether PJM implements scarcity pricing. Scarcity pricing transparency requires greater transparency around the processes used to commit and dispatch reserves and to calculate prices.

41 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 107 (Sep. 26, 2019)

Real-Time SCED and LPC

LPC uses data from an approved RT SCED solution that was used to dispatch the resources in the system. On average, PJM operators approve more than one RT SCED case per five minute interval to send dispatch signals to resources. PJM operators select only a subset of these approved RT SCED cases to be used in LPC to calculate real-time LMPs. Generally, LPC uses the latest available approved RT SCED case to calculate prices. However, LPC assigns the prices to a target interval that is different from the target interval of the RT SCED case it used.

PJM operators approve a larger number of RT SCED cases to send dispatch signals to generators than the number of RT SCED cases used to calculate prices in LPC. As a result, a number of dispatch directives are not reflected in real-time energy market prices.

Figure 3-26 shows, on a daily basis for the first nine months of 2019, the total number of solved RT SCED cases, the number of operator approved RT SCED cases, and the number of RT SCED cases that were used in LPC to calculate five minute LMPs. Table 3-34 shows, on a monthly basis for the first nine months of 2019, the number of solved RT SCED cases, the number and percent of solved cases that were approved and the number and percent of solved cases used in LPC. RT SCED is executed every three minutes. Each execution of RT SCED produces three solutions, using three different levels of load bias. Since prices are calculated every five minutes while three SCED solutions are produced every three minutes, there is a larger number of solved SCED cases than are five minute intervals in any given period. Table 3-34 shows that only 61.5 percent of approved RT SCED cases that are used to send dispatch signals to generators are used in calculating real-time energy market prices. This weakens the incentives to follow dispatch by generators, especially when RT SCED cases that reflect shortage pricing are not used in calculating real-time prices in LPC.

Figure 3-26 Daily RT SCED cases solved, approved and used in pricing: January through September, 2019

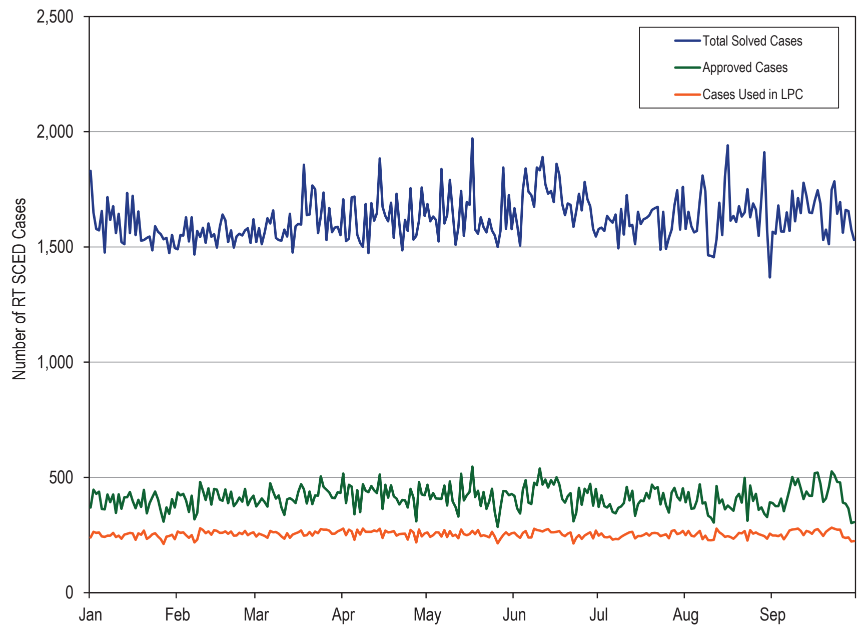


Table 3-34 RT SCED cases solved, approved and used in pricing: January through September, 2019

Month (2019)	Number of Solved RT SCED Cases	Number of Approved RT SCED Cases	Number of Approved RT SCED Cases Used in LPC	Approved RT SCED Cases as Percent of Solved Cases	RT SCED Cases Used in LPC as Percent of Solved Cases	RT SCED Cases Used in LPC as Percent of Approved Cases
Jan	49,158	12,177	7,656	24.8%	15.6%	62.9%
Feb	43,628	11,484	7,186	26.3%	16.5%	62.6%
Mar	49,753	12,942	7,966	26.0%	16.0%	61.6%
Apr	48,765	12,759	7,768	26.2%	15.9%	60.9%
May	50,772	12,890	7,808	25.4%	15.4%	60.6%
Jun	51,299	12,988	7,651	25.3%	14.9%	58.9%
Jul	50,011	12,484	7,752	25.0%	15.5%	62.1%
Aug	50,769	12,012	7,731	23.7%	15.2%	64.4%
Sep	49,276	12,870	7,737	26.1%	15.7%	60.1%
Total	443,431	112,606	69,255	25.4%	15.6%	61.5%

PJM's process of selecting approved RT SCED cases to use in LPC to calculate LMPs has an inconsistency that leads to downstream impacts for energy and reserve settlements. The MMU has identified systematic differences in the target intervals for the RT SCED cases approved to send dispatch signals to generators, and the cases used to calculate energy and ancillary service prices in LPC. RT SCED solves the dispatch problem for a target interval that is generally 10 to 14 minutes in the future. An RT SCED case is approved and sends dispatch signals to generators. The approved RT SCED case is then used to calculate LMPs in LPC. However, the target interval in LPC is consistently before the target interval from the RT SCED case used for the dispatch signal. For example the LPC case that calculates prices for the interval beginning 10:00 EPT uses an approved RT SCED case that sent MW dispatch signals for the target interval 10:10 EPT. This discrepancy leads to a mismatch between the MW dispatch and real-time LMPs.

Table 3-35 compares the RT SCED and LPC target intervals for the first nine months of 2019. Table 3-35 shows that in the first nine months of 2019, 67.7 percent of the five minute intervals have prices assigned for a target interval that is 10 minutes prior to the dispatch target interval and 27.5 percent of five minute intervals have prices assigned for a target interval that is five minutes prior to the dispatch target interval.

Table 3-35 Difference in RT SCED and LPC target intervals: January through September, 2019

Difference between RT SCED and LPC Target Intervals (mins)	Percent of Five Minute Intervals
(10)	0.1%
(5)	0.5%
0	4.0%
5	27.5%
10	67.7%

For correct price signals and compensation, LMP and ancillary service pricing should align with the dispatch solution that creates those prices for each and every real-time market interval.[42] The MMU recommends that PJM approve one RT SCED case for each five minute interval to send dispatch signals, and that PJM calculate prices for that five minute interval using the same approved SCED case.

Recalculation of Five Minute Real-Time Prices

PJM's five minute interval LMPs are obtained from solved LPC optimization cases. PJM recalculates five minute interval real-time LMPs as it believes necessary to correct errors. To do so, PJM reruns LPC optimization cases with modified inputs. The PJM OATT allows for posting of recalculated real-time prices no later than 5:00 p.m. of the tenth calendar day following the

42 *See* Order No. 825: Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, 155 FERC ¶ 61,276 (June 16, 2016).

operating day. The OATT also requires PJM to notify market participants of the underlying error no later than 5:00 pm of the second business day following the operating day.[43] Table 3-36 shows the number of five minute intervals in each month and number of five minute intervals in each month for which PJM recalculated real-time prices. In the first nine months of 2019, among 78,612 five minute intervals, PJM recalculated LMPs for 334 five minute intervals or 0.42 percent of the total five minute intervals in the first nine months.

Table 3-36 Number of five minute interval real-time prices recalculated, January through September, 2019

Month	Number of Five Minute Intervals	Number of Five Minute Intervals for which LMPs were recalculated
January	8,928	10
February	8,064	14
March	8,916	51
April	8,640	19
May	8,928	19
June	8,640	28
July	8,928	69
August	8,928	79
September	8,640	45
Total	78,612	334

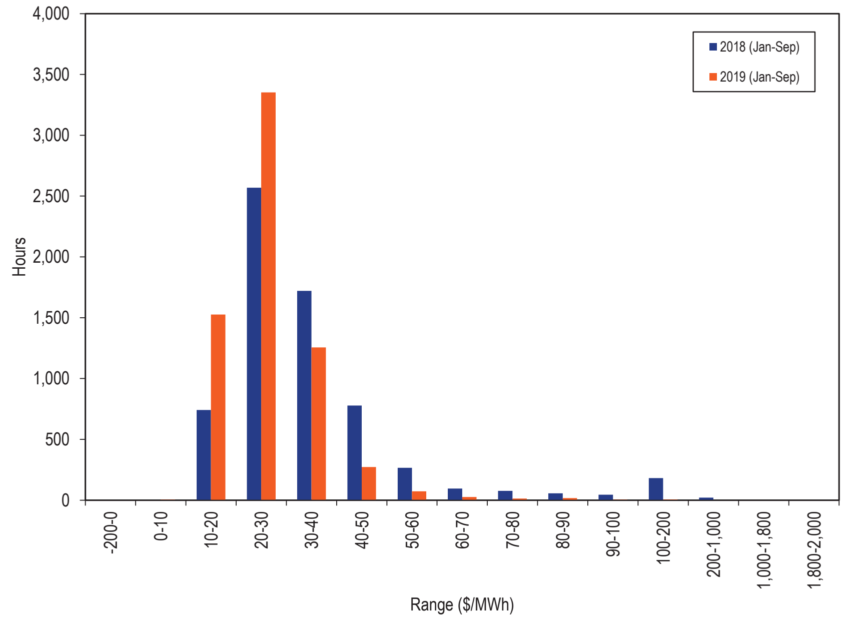
Day-Ahead Average LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[44]

PJM Day-Ahead Average LMP Duration

Figure 3-27 shows the hourly distribution of PJM day-ahead average LMP in the first nine months of 2018 and 2019.

Figure 3-27 Average LMP for the Day-Ahead Energy Market: January through September, 2018 and 2019



43 OATT Attachment K § 1.10.8(e).

44 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 3-37 shows the PJM day-ahead, average LMP in the first nine months of 2000 through 2019.

Table 3-37 Day-ahead, average LMP (Dollars per MWh): January through September, 2000 through 2019

	Day-Ahead LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$28.19	$21.10	$19.10	NA	NA	NA
2001	$36.07	$30.02	$34.25	28.0%	42.3%	79.4%
2002	$28.29	$22.54	$19.09	(21.6%)	(24.9%)	(44.3%)
2003	$41.20	$38.24	$22.02	45.6%	69.7%	15.4%
2004	$42.64	$42.07	$17.47	3.5%	10.0%	(20.7%)
2005	$54.48	$46.67	$28.83	27.8%	10.9%	65.1%
2006	$50.45	$46.32	$24.93	(7.4%)	(0.8%)	(13.5%)
2007	$54.24	$51.40	$24.95	7.5%	11.0%	0.1%
2008	$71.43	$66.38	$33.11	31.7%	29.2%	32.7%
2009	$37.35	$35.29	$14.32	(47.7%)	(46.8%)	(56.8%)
2010	$45.81	$41.03	$19.59	22.7%	16.3%	36.8%
2011	$45.14	$40.20	$22.68	(1.5%)	(2.0%)	15.7%
2012	$32.16	$30.10	$14.54	(28.8%)	(25.1%)	(35.9%)
2013	$37.50	$34.70	$16.96	16.6%	15.3%	16.6%
2014	$53.76	$39.92	$58.98	43.4%	15.0%	247.8%
2015	$36.67	$30.56	$25.21	(31.8%)	(23.4%)	(57.3%)
2016	$27.90	$25.23	$11.37	(23.9%)	(17.4%)	(54.9%)
2017	$28.90	$26.60	$10.73	3.6%	5.4%	(5.6%)
2018	$36.04	$29.75	$25.12	24.7%	11.8%	134.2%
2019	$26.41	$24.76	$9.58	(26.7%)	(16.8%)	(61.9%)

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 3-38 shows the PJM day-ahead, load-weighted, average LMP in the first nine months of 2000 through 2019.

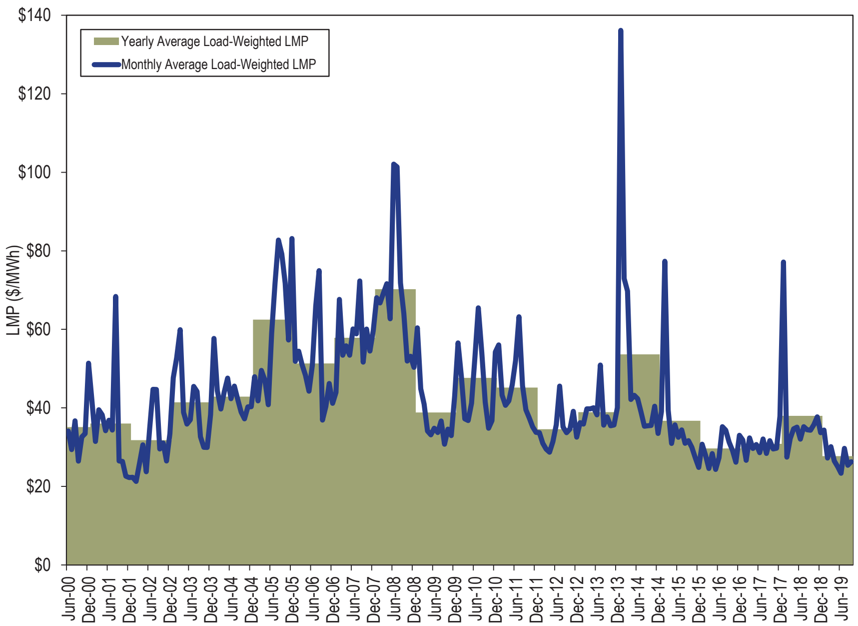
Table 3-38 Day-ahead, load-weighted, average LMP (Dollars per MWh): January through September, 2000 through 2019

	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	31.5%	26.5%	35.0%
2009	$39.35	$36.92	$14.98	(48.2%)	(47.5%)	(57.4%)
2010	$49.12	$43.33	$21.35	24.8%	17.4%	42.6%
2011	$48.34	$42.35	$26.54	(1.6%)	(2.3%)	24.3%
2012	$34.29	$31.17	$17.12	(29.1%)	(26.4%)	(35.5%)
2013	$39.49	$35.96	$19.90	15.1%	15.4%	16.3%
2014	$59.09	$42.08	$67.27	49.6%	17.0%	238.0%
2015	$39.51	$32.15	$28.05	(33.1%)	(23.6%)	(58.3%)
2016	$29.69	$26.60	$12.38	(24.8%)	(17.3%)	(55.8%)
2017	$30.26	$27.95	$11.59	1.9%	5.1%	(6.4%)
2018	$38.71	$31.62	$27.75	27.9%	13.1%	139.5%
2019	$27.70	$25.85	$10.40	(28.4%)	(18.3%)	(62.5%)

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

Figure 3-28 shows the PJM day-ahead, monthly and annual, load-weighted LMP from June 1, 2000 through September 30, 2019.[45]

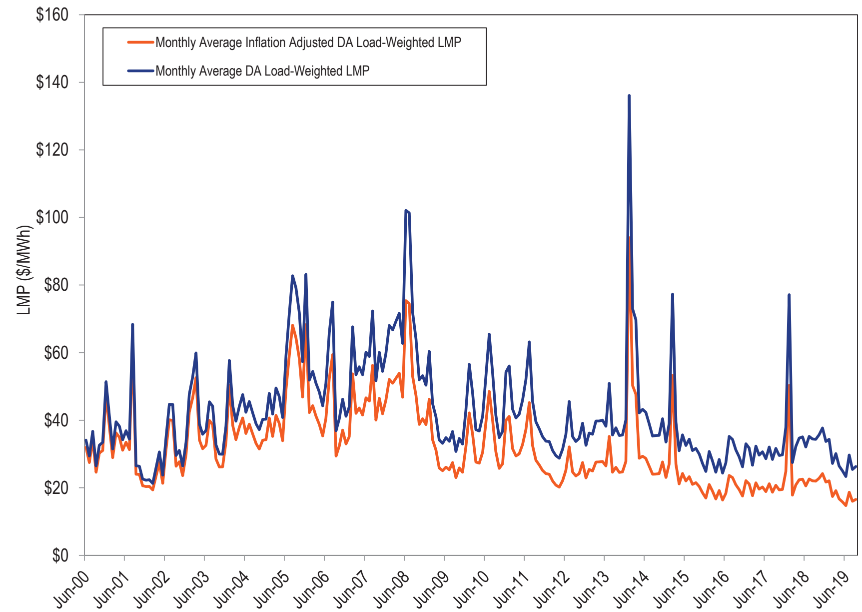
Figure 3-28 Day-ahead, monthly and annual, load-weighted, average LMP: June 2000 through September 2019



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

Figure 3-29 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 2019.[46] Table 3-39 shows the PJM day-ahead load-weighted average LMP and inflation adjusted load-weighted average LMP for the first nine months of every year from 2000 through 2019. The PJM day-ahead inflation adjusted load-weighted average LMP for January through September, 2019 was the lowest nine month value since PJM day-ahead markets started in 2000. The day-ahead inflation adjusted monthly load-weighted average LMP for June 2019 ($14.73 per MWh) was the lowest monthly value since 2000.

Figure 3-29 Day-ahead, monthly, load-weighted, average LMP unadjusted and inflation adjusted: June 2000 through September 2019



45 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.

46 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 1, 2019).

Table 3-39 Day-ahead, yearly, load-weighted, average LMP unadjusted and inflation adjusted: January through September, 2000 through 2019

	Load-Weighted, Average LMP	Inflation Adjusted Load-Weighted, Average LMP
2000	$31.81	$29.74
2001	$39.88	$36.41
2002	$32.29	$29.02
2003	$44.11	$38.81
2004	$44.59	$38.26
2005	$59.51	$49.32
2006	$54.19	$43.40
2007	$57.79	$45.19
2008	$75.96	$56.73
2009	$39.35	$29.77
2010	$49.12	$36.46
2011	$48.34	$34.79
2012	$34.29	$24.17
2013	$39.49	$27.40
2014	$59.09	$40.45
2015	$39.51	$26.99
2016	$29.69	$20.03
2017	$30.26	$19.99
2018	$38.71	$24.98
2019	$27.70	$17.55

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 3-40 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 2018 and 2019. In the first nine months of 2019, 48.9 percent of all cleared UTC transactions were net profitable. Of cleared UTC transactions, 67.0 percent were profitable on the source side and 33.5 were profitable on the sink side but only 6.5 percent were profitable on both the source and sink side.

Table 3-40 Cleared UTC profitability by source and sink point: January through September, 2018 and 2019[47]

(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
2018	7,480,780	3,730,433	4,763,121	2,768,109	422,976	49.9%	63.7%	37.0%	5.7%
2019	6,953,487	3,399,845	4,656,194	2,329,766	450,234	48.9%	67.0%	33.5%	6.5%

Table 3-41 shows the number of cleared INC and DEC transactions, the number of profitable cleared transactions in the first nine months of 2018 and 2019. Of cleared INC and DEC transactions in the first nine months of 2019, 67.9 percent of INCs were profitable and 35.4 percent of DECs were profitable.

Table 3-41 Cleared INC and DEC profitability: January through September, 2018 and 2019

(Jan-Sep)	Cleared INC	Profitable INC	Profitable INC Percent	Cleared DEC	Profitable DEC	Profitable DEC Percent
2018	1,549,323	1,015,130	65.5%	1,182,673	452,282	38.2%
2019	1,628,241	1,105,533	67.9%	1,364,023	482,371	35.4%

47 Calculations exclude PJM administrative charges.

Figure 3-30 shows total UTC daily gross profits, the sum of all positive profit UTC transactions, gross losses, the sum of all negative profit UTC transactions, and net profits and losses in the first nine months of 2019.

Figure 3-30 UTC daily gross profits and losses and net profits: January through September, 2019[48]

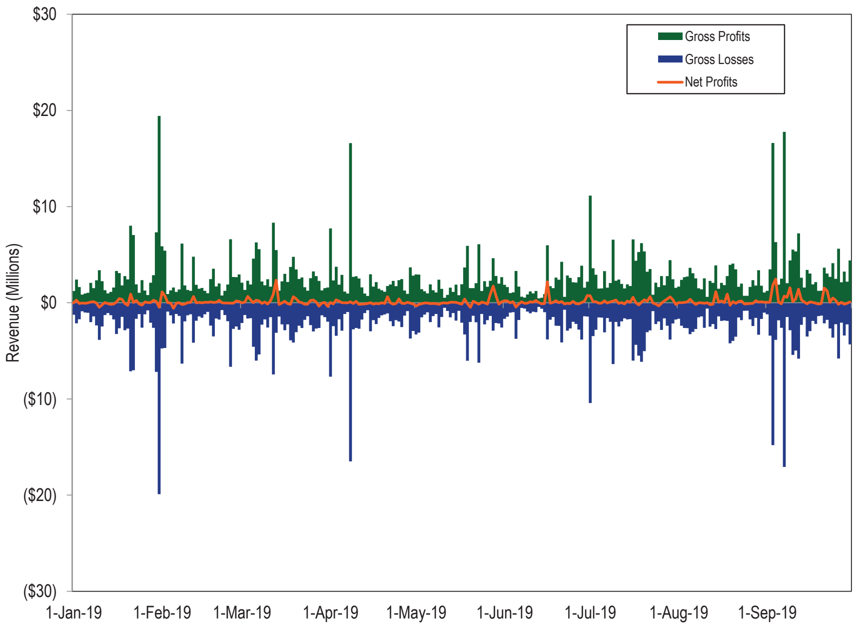
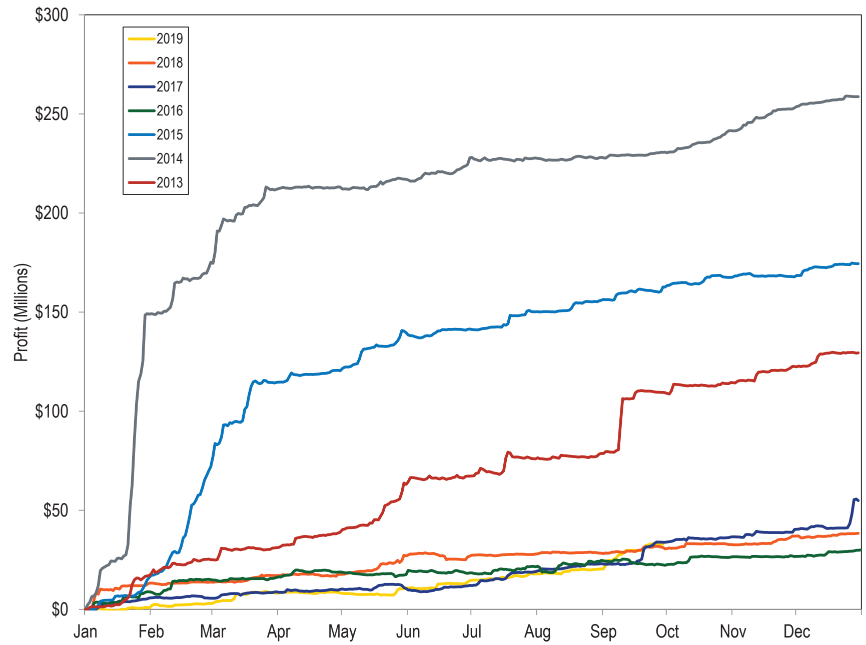


Figure 3-31 shows the cumulative UTC daily profits for January 1, 2013 through September 30, 2019. UTC profits during this period were primarily a result of significant unanticipated price differences between day-ahead and real-time LMPs.

Figure 3-31 Cumulative daily UTC profits: January 2013 through September 2019



48 Calculations exclude PJM administrative charges.

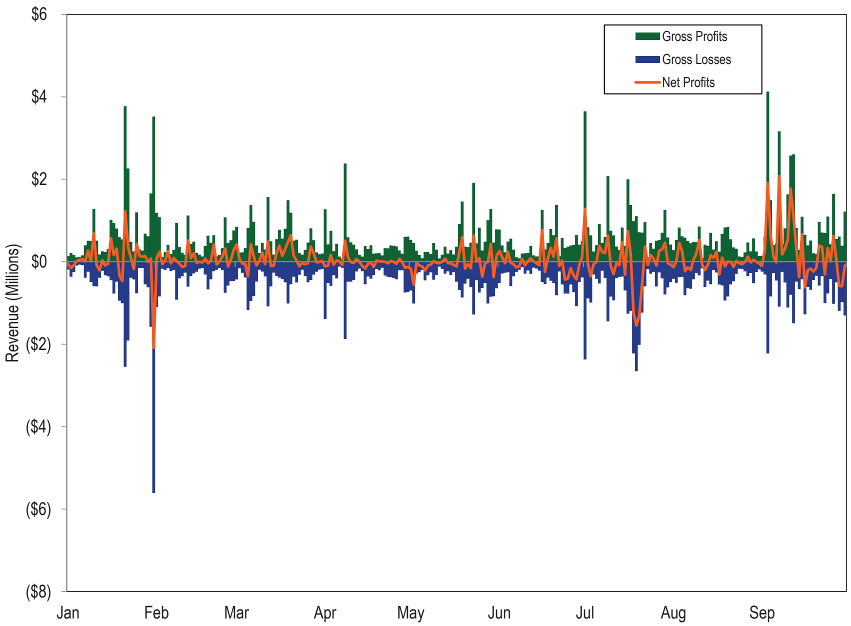
Table 3-42 shows UTC profits by month for January 1, 2013 through September 30, 2019. May 2016, September 2016, February 2017 and June 2018 were the only months in the past six years where the total monthly profits were negative.

Table 3-42 UTC profits by month: January 2013 through September 2019

	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	$1,452,515	$4,339,363	$1,358,446	$38,373,436
2019	$574,901	$2,407,307	$5,287,985	$332,036	$1,833,879	$3,382,009	$4,066,461	$2,442,971	$12,599,278				$32,926,829

Figure 3-32 shows total INC and DEC daily gross profits, the sum of all positive profit transactions, gross losses, the sum of all negative profit transactions, and net profits and losses in the first nine months of 2019.

Figure 3-32 INC and DEC daily gross profits and losses and net profits: January through September, 2019[49]



49 Calculations exclude PJM administrative charges.

Figure 3-33 shows total INC daily gross profits and losses and net profits and losses in the first nine months of 2019.

Figure 3-33 INC daily gross profits and losses and net profits: January through September, 2019[50]

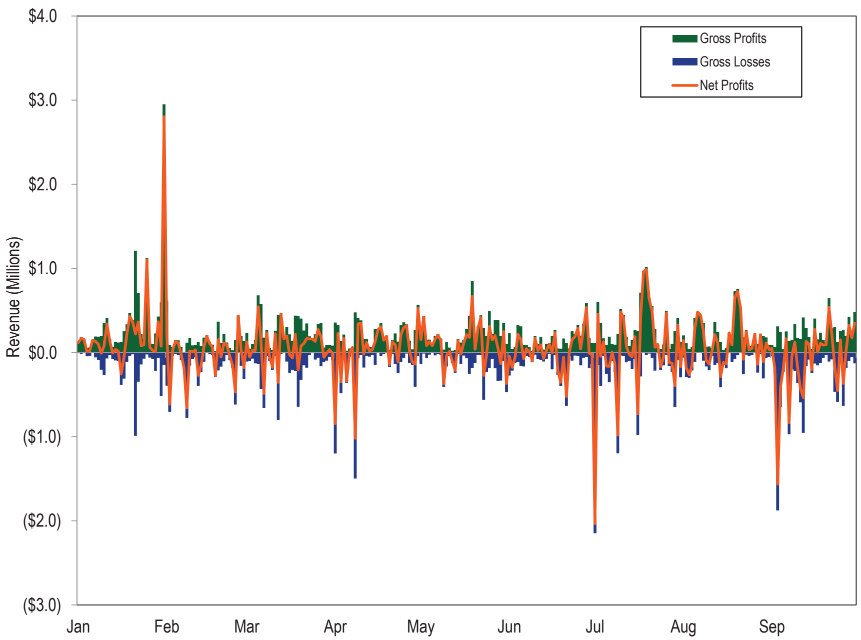
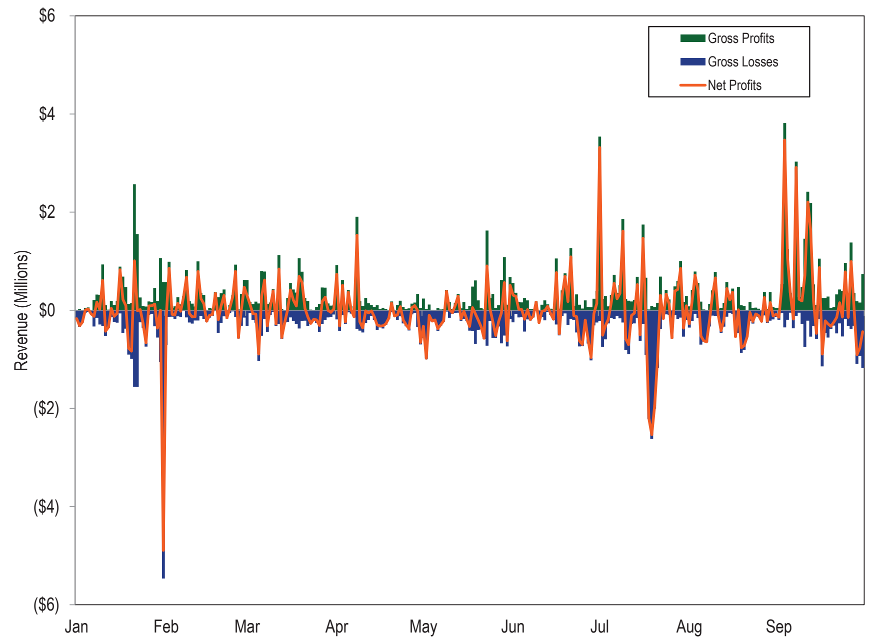


Figure 3-34 shows total DEC daily gross profits and losses and net profits and losses in the first nine months of 2019.

Figure 3-34 DEC daily gross profits and losses and net profits: January through September, 2019[51]



50 Calculations exclude PJM administrative charges.

51 Calculations exclude PJM administrative charges.

Figure 3-35 shows the cumulative INC and DEC daily profits for January 1, through September 30, 2019.

Figure 3-35 Cumulative daily INC and DEC profits: January through September, 2019

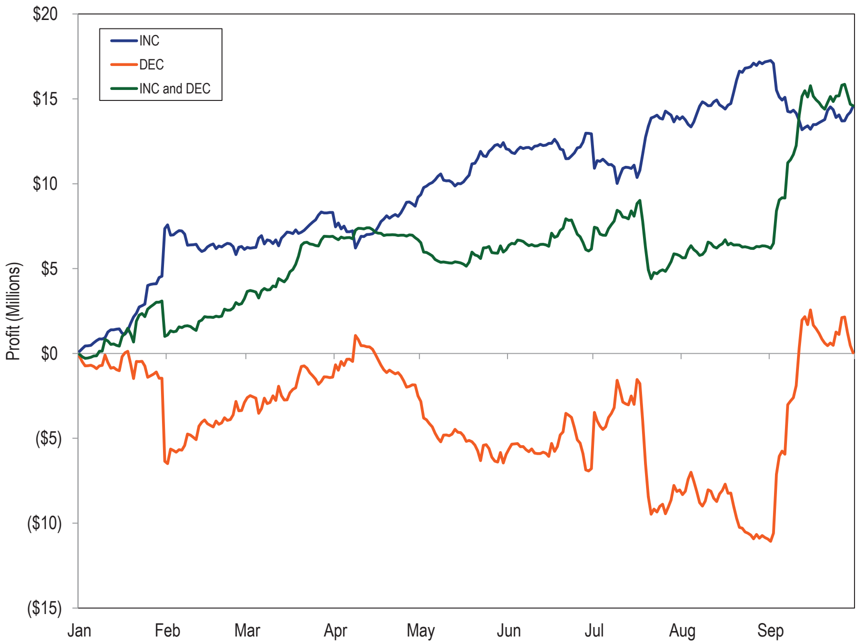


Table 3-43 shows INC and DEC profits by month for January 1, through September 30, 2019.

Table 3-43 INC and DEC profits by month: January through September, 2019

	January	February	March	April	May	June	July	August	September	Total
INCs	$7,354,057	($1,229,270)	$2,180,622	$898,417	$2,853,902	$885,231	$856,466	$3,417,744	($2,653,011)	$14,564,157
DECs	($6,349,787)	$3,455,508	$1,497,078	($1,109,340)	($3,439,754)	($841,301)	($1,256,859)	($2,882,716)	$10,958,759	$31,587
INCs and DECs	$1,004,269	$2,226,238	$3,677,699	($210,923)	($585,853)	$43,930	($400,393)	$535,027	$8,305,748	$14,595,744

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 3-37).

Table 3-44 shows that the difference between the average real-time price and the average day-ahead price was $0.48 per MWh in the first nine months of 2018, and -$0.11 per MWh in the first nine months of 2019. The difference between average peak real-time price and the average peak day-ahead price was -$0.20 per MWh in the first nine months of 2018 and -$0.32 per MWh in the first nine months of 2019.

Table 3-44 Day-ahead and real-time average LMP (Dollars per MWh): January through September, 2018 and 2019[52]

	2018 (Jan-Sep)				2019 (Jan-Sep)			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$36.04	$36.52	$0.48	1.3%	$26.41	$26.30	($0.11)	(0.4%)
Median	$29.75	$27.26	($2.48)	(9.1%)	$24.76	$23.39	($1.37)	(5.8%)
Standard deviation	$25.12	$33.22	$8.10	24.4%	$9.58	$17.69	$8.11	45.9%
Peak average	$41.90	$41.70	($0.20)	(0.5%)	$30.72	$30.39	($0.32)	(1.1%)
Peak median	$35.92	$32.30	($3.62)	(11.2%)	$28.38	$26.03	($2.34)	(9.0%)
Peak standard deviation	$25.56	$31.13	$5.57	17.9%	$9.98	$20.67	$10.69	51.7%
Off peak average	$30.91	$31.98	$1.07	3.3%	$22.63	$22.71	$0.08	0.3%
Off peak median	$24.37	$23.44	($0.93)	(4.0%)	$21.24	$20.53	($0.71)	(3.5%)
Off peak standard deviation	$23.57	$34.31	$10.74	31.3%	$7.37	$13.61	$6.25	45.9%

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

Table 3-45 shows the difference between the real-time load-weighted and the day-ahead load-weighted energy market prices for the first nine months of 2001 through 2019.

Table 3-45 Day-ahead load-weighted and real-time load-weighted average LMP (Dollars per MWh): January through September, 2001 through 2019

(Jan-Sep)	Day-Ahead	Real-Time	Difference	Percent of Real Time
2001	$36.07	$36.00	($0.07)	(0.2%)
2002	$28.29	$28.13	($0.16)	(0.6%)
2003	$41.20	$40.42	($0.77)	(1.9%)
2004	$42.64	$43.85	$1.22	2.9%
2005	$54.48	$54.69	$0.21	0.4%
2006	$50.45	$51.79	$1.34	2.7%
2007	$54.24	$57.34	$3.10	5.7%
2008	$71.43	$71.94	$0.51	0.7%
2009	$37.35	$37.42	$0.08	0.2%
2010	$45.81	$46.13	$0.32	0.7%
2011	$45.14	$45.79	$0.65	1.4%
2012	$32.16	$32.45	$0.29	0.9%
2013	$37.50	$37.30	($0.20)	(0.5%)
2014	$53.76	$52.72	($1.04)	(1.9%)
2015	$36.67	$35.96	($0.70)	(1.9%)
2016	$27.90	$27.43	($0.47)	(1.7%)
2017	$28.90	$28.79	($0.11)	(0.4%)
2018	$36.04	$36.52	$0.48	1.3%
2019	$26.41	$26.30	($0.11)	(0.4%)

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

Table 3-46 provides frequency distributions of the differences between PJM real-time load-weighted hourly LMP and PJM day-ahead load-weighted hourly LMP for the first nine months of 2018 and 2019.

Table 3-46 Frequency distribution by hours of real-time load-weighted LMP minus day-ahead load-weighted LMP (Dollars per MWh): January through September, 2018 and 2019

	2018 (Jan-Sep)		2019 (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)	1	0.02%	0	0.00%
($150) to ($100)	3	0.06%	0	0.00%
($100) to ($50)	31	0.53%	5	0.08%
($50) to $0	4,130	63.58%	4,400	67.24%
$0 to $50	2,244	97.83%	2,102	99.33%
$50 to $100	102	99.39%	22	99.66%
$100 to $150	24	99.76%	14	99.88%
$150 to $200	5	99.83%	1	99.89%
$200 to $250	8	99.95%	3	99.94%
$250 to $300	1	99.97%	1	99.95%
$300 to $350	1	99.98%	1	99.97%
$350 to $400	0	99.98%	0	99.97%
$400 to $450	1	100.00%	0	99.97%
$450 to $500	0	100.00%	0	99.97%
$500 to $750	0	100.00%	2	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 3-36 shows the hourly differences between day-ahead and real-time hourly LMP in the first nine months of 2019.

Figure 3-36 Real-time hourly LMP minus day-ahead hourly LMP: January through September, 2019

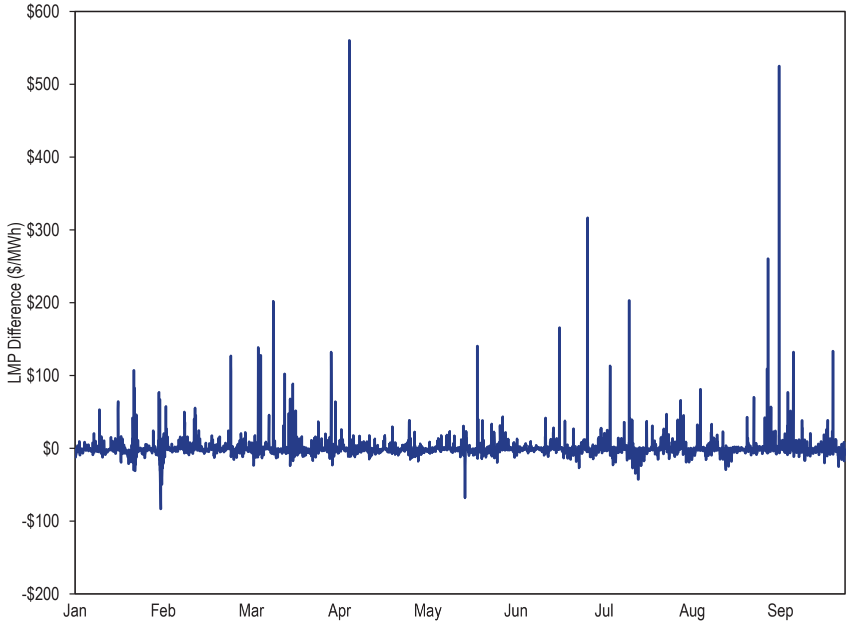


Figure 3-37 shows the monthly average, and monthly absolute value, of the differences between the day-ahead and real-time PJM average LMPs in the first nine months of 2019.

Figure 3-37 Monthly average, and monthly absolute value, of real-time minus day-ahead LMP: January 2013 through September 2019

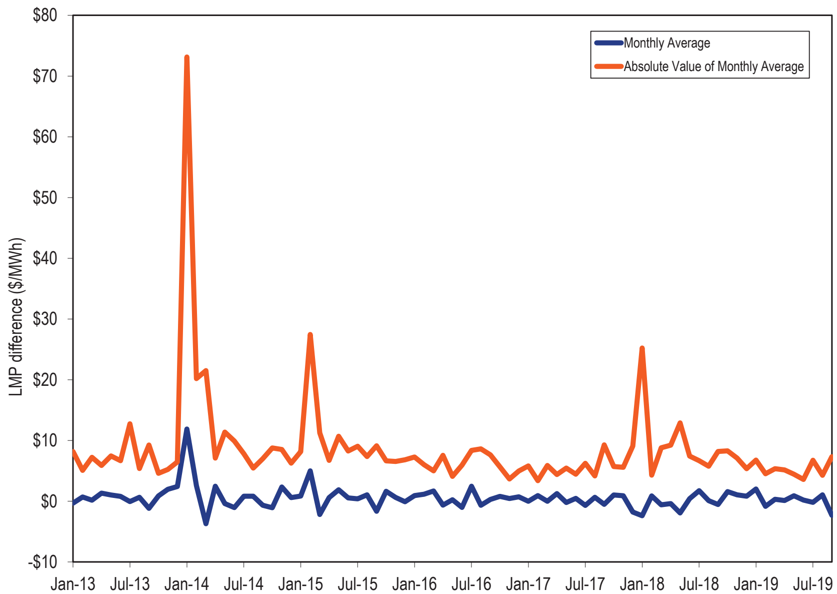
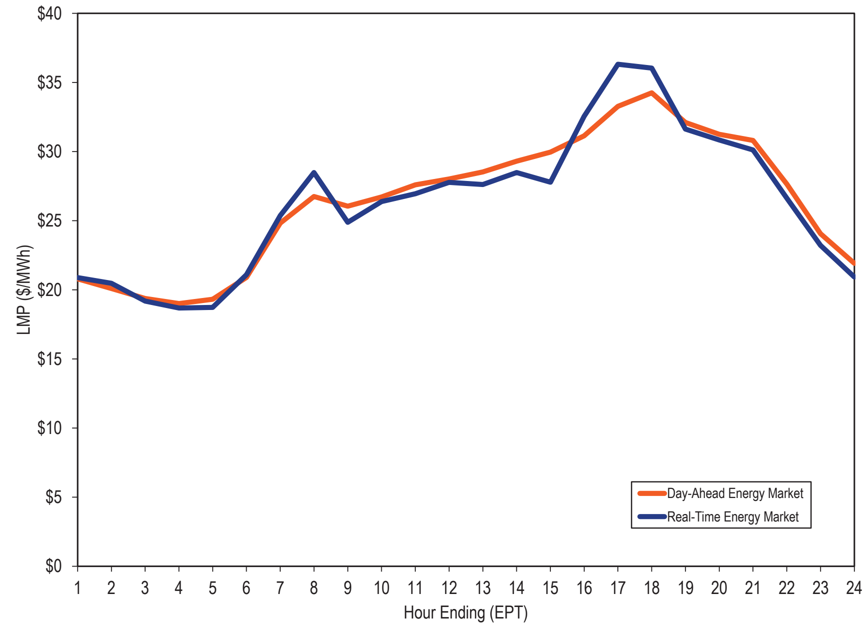


Figure 3-38 shows day-ahead and real-time load-weighted LMP on an average hourly basis for the first nine months of 2019. Hour ending 17 had the largest difference between the DA and RT load-weighted LMP, at $3.04 per MWh, and hour ending 1 had the smallest difference at $0.08 per MWh. The average for the first nine months of 2019 was $0.11 per MWh lower in the RT LMP than DA LMP.

Figure 3-38 System hourly average LMP: January through September, 2019



Zonal LMP and Dispatch

Table 3-47 shows zonal real-time, and real-time, load-weighted, average LMP in the first nine months of 2018 and 2019.

Table 3-47 Zonal real-time and real-time, load-weighted, average LMP (Dollars per MWh): January through September, 2018 and 2019

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change
AECO	$34.67	$24.61	(29.0%)	$37.27	$25.95	(30.4%)
AEP	$36.20	$26.94	(25.6%)	$38.79	$28.19	(27.3%)
APS	$38.06	$26.71	(29.8%)	$41.51	$28.02	(32.5%)
ATSI	$38.80	$26.96	(30.5%)	$41.48	$28.12	(32.2%)
BGE	$42.03	$29.11	(30.7%)	$46.51	$31.03	(33.3%)
ComEd	$28.25	$24.04	(14.9%)	$29.97	$25.20	(15.9%)
DAY	$37.25	$27.87	(25.2%)	$39.98	$29.32	(26.7%)
DEOK	$37.55	$26.88	(28.4%)	$40.56	$28.23	(30.4%)
DLCO	$40.41	$27.64	(31.6%)	$45.28	$29.16	(35.6%)
Dominion	$38.32	$26.43	(31.0%)	$44.03	$29.26	(33.5%)
DPL	$38.42	$26.59	(30.8%)	$41.19	$27.79	(32.5%)
EKPC	$33.44	$26.46	(20.9%)	$36.98	$28.07	(24.1%)
JCPL	$34.91	$24.58	(29.6%)	$38.10	$26.10	(31.5%)
Met-Ed	$34.46	$25.43	(26.2%)	$37.97	$26.92	(29.1%)
OVEC	NA	$25.97	NA	NA	$26.33	NA
PECO	$34.42	$24.30	(29.4%)	$37.63	$25.67	(31.8%)
PENELEC	$36.34	$25.54	(29.7%)	$38.83	$26.56	(31.6%)
Pepco	$40.77	$28.15	(31.0%)	$44.76	$29.79	(33.5%)
PPL	$33.63	$23.89	(29.0%)	$37.33	$25.21	(32.5%)
PSEG	$35.18	$24.89	(29.2%)	$37.70	$26.06	(30.9%)
RECO	$35.54	$25.09	(29.4%)	$38.30	$26.37	(31.2%)
PJM	$36.52	$26.30	(28.0%)	$39.43	$27.60	(30.0%)

Table 3-48 shows zonal day-ahead, and day-ahead, load-weighted, average LMP in the first nine months of 2018 and 2019.[53]

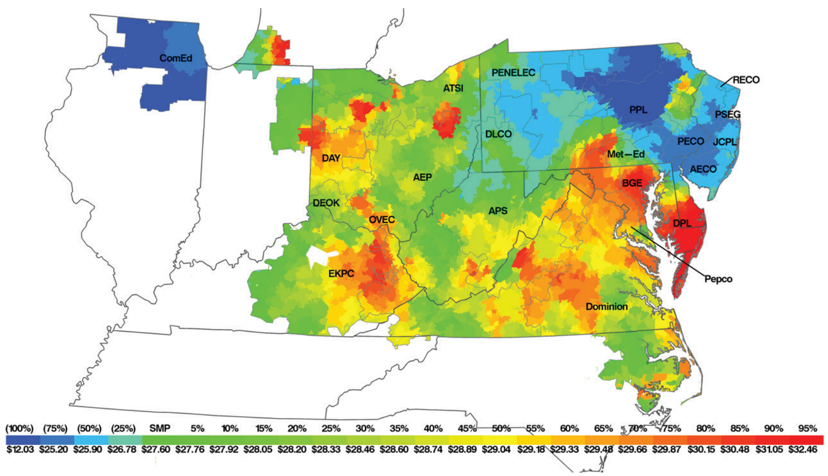
Table 3-48 Zonal day-ahead and day-ahead, load-weighted, average LMP (Dollars per MWh): January through September, 2018 and 2019

	Day-Ahead Average LMP			Day-Ahead, Load-Weighted, Average LMP		
Zone	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change	2018 (Jan-Sep)	2019 (Jan-Sep)	Percent Change
AECO	$34.66	$24.55	(29.2%)	$36.95	$25.76	(30.3%)
AEP	$35.53	$26.92	(24.2%)	$37.90	$28.23	(25.5%)
APS	$37.42	$26.92	(28.1%)	$40.21	$28.22	(29.8%)
ATSI	$37.35	$27.24	(27.1%)	$39.53	$28.42	(28.1%)
BGE	$41.57	$29.48	(29.1%)	$45.54	$31.38	(31.1%)
ComEd	$28.06	$24.26	(13.5%)	$29.80	$25.35	(14.9%)
DAY	$36.90	$28.01	(24.1%)	$39.43	$29.43	(25.3%)
DEOK	$38.09	$27.28	(28.4%)	$41.25	$28.77	(30.3%)
DLCO	$40.18	$28.04	(30.2%)	$44.78	$29.70	(33.7%)
Dominion	$37.83	$26.12	(30.9%)	$42.98	$28.73	(33.2%)
DPL	$37.29	$26.86	(28.0%)	$39.70	$28.02	(29.4%)
EKPC	$33.14	$26.43	(20.3%)	$36.25	$28.11	(22.5%)
JCPL	$34.78	$24.47	(29.7%)	$37.44	$25.75	(31.2%)
Met-Ed	$34.67	$25.08	(27.7%)	$37.51	$26.35	(29.7%)
OVEC	NA	$25.98	NA	NA	$29.70	NA
PECO	$34.36	$24.04	(30.0%)	$36.96	$25.19	(31.8%)
PENELEC	$35.44	$25.97	(26.7%)	$37.95	$27.38	(27.9%)
Pepco	$40.44	$28.61	(29.3%)	$44.15	$30.33	(31.3%)
PPL	$33.59	$23.86	(29.0%)	$36.66	$25.05	(31.7%)
PSEG	$35.47	$24.81	(30.1%)	$37.97	$25.94	(31.7%)
RECO	$35.59	$25.34	(28.8%)	$38.05	$26.78	(29.6%)
PJM	$36.04	$26.41	(26.7%)	$38.71	$27.70	(28.4%)

53 The OVEC Zone did not have any day-ahead load in 2018.

Figure 3-39 is a map of the real-time, load-weighted, average LMP in the first nine months of 2019. 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.

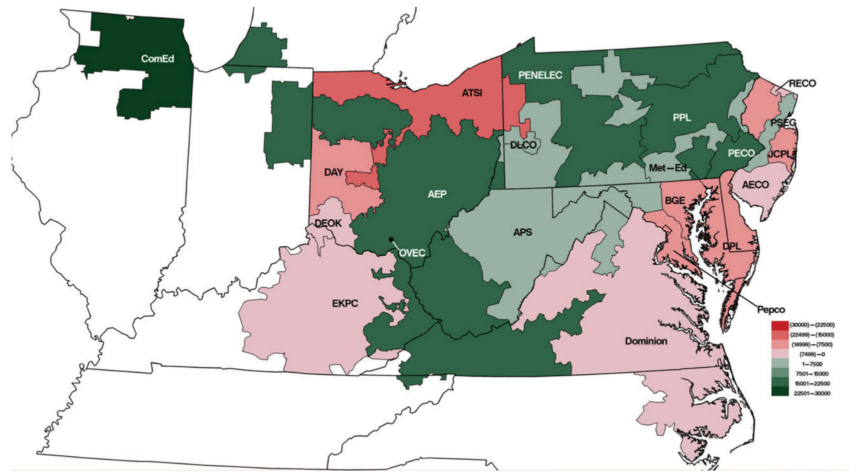
Figure 3-39 Real-time, load-weighted, average LMP: January through September, 2019



Net Generation by Zone

Figure 3-40 shows the difference between the PJM real-time generation and real-time load by zone in in the first nine months of 2019. Figure 3-40 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 3-49 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2018 and 2019.

Figure 3-40 Map of real-time generation, less real-time load, by zone: January through September, 2019[54]



54 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>.

Table 3-49 Real-time generation less real-time load by zone (GWh): January through September, 2018 and 2019

Zonal Generation and Load (GWh)						
Jan-Sep	2018			2019		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	4,242.8	7,867.9	(3,625.1)	4,628.6	7,706.6	(3,078.0)
AEP	123,589.1	97,834.0	25,755.1	112,736.6	95,294.1	17,442.5
APS	35,587.8	37,502.7	(1,914.8)	38,336.0	37,010.6	1,325.3
ATSI	29,389.7	51,351.5	(21,961.9)	30,033.3	49,525.0	(19,491.6)
BGE	16,196.6	24,178.2	(7,981.6)	13,670.1	23,908.7	(10,238.6)
ComEd	100,500.7	74,776.7	25,724.0	101,601.2	71,864.4	29,736.8
DAY	4,504.3	13,273.5	(8,769.2)	827.8	13,057.7	(12,230.0)
DEOK	13,325.7	21,067.3	(7,741.6)	15,239.3	20,554.2	(5,314.9)
Dominion	73,760.9	76,737.1	(2,976.1)	76,091.4	76,949.2	(857.9)
DPL	5,052.1	14,373.1	(9,321.0)	4,265.1	14,052.0	(9,786.9)
DLCO	12,211.4	10,622.5	1,588.9	12,577.3	10,224.9	2,352.4
EKPC	7,007.3	9,970.2	(2,962.8)	5,218.7	9,579.6	(4,360.9)
JCPL	12,900.4	17,662.1	(4,761.7)	8,811.3	16,953.4	(8,142.2)
Met-Ed	17,255.1	11,911.8	5,343.3	18,219.4	11,731.7	6,487.7
OVEC	0.0	0.0	0.0	8,169.2	97.9	8,071.3
PECO	50,623.4	31,075.1	19,548.3	52,836.8	30,342.4	22,494.4
PENELEC	32,966.8	12,986.4	19,980.4	30,321.2	12,649.6	17,671.6
Pepco	9,471.3	23,140.5	(13,669.2)	9,092.4	22,660.4	(13,567.9)
PPL	41,907.0	30,831.8	11,075.2	48,893.1	30,485.2	18,407.8
PSEG	35,525.9	33,755.6	1,770.3	34,257.8	32,754.0	1,503.8
RECO	0.0	1,152.6	(1,152.6)	0.0	1,104.0	(1,104.0)

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.

Fuel Prices, LMP, and Dispatch

Energy Production by Fuel Source

Table 3-50 shows PJM generation by fuel source in GWh for the first nine months of 2018 and 2019. In the first nine months of 2019, generation from coal units decreased 16.4 percent, generation from natural gas units increased 17.2 percent, and generation from oil decreased 49.4 percent compared to the first nine months of 2018.[55] The increase in gas fired generation offsets the decreases in coal, oil and nuclear generation. Wind and solar output rose by 2,405 GWh compared to the first nine months of 2018, supplying 3.03 percent of PJM energy in the first nine months of 2019.

55 Generation data are the sum of GWh 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.

Table 3-50 Generation (By fuel source (GWh)): January through September, 2018 and 2019[56 57 58]

	2018 (Jan - Sep)		2019 (Jan - Sep)		Change in
	GWh	Percent	GWh	Percent	Output
Coal	185,756.1	29.2%	155,308.3	24.5%	(16.4%)
Bituminous	155,985.6	24.5%	132,915.7	21.0%	(14.8%)
Sub Bituminous	23,582.9	3.7%	17,661.9	2.8%	(25.1%)
Other Coal	6,187.5	1.0%	4,730.8	0.7%	(23.5%)
Nuclear	214,603.2	33.8%	210,542.6	33.2%	(1.9%)
Gas	196,583.1	30.9%	229,892.5	36.2%	16.9%
Natural Gas	194,845.4	30.7%	228,282.7	36.0%	17.2%
Landfill Gas	1,724.1	0.3%	1,606.4	0.3%	(6.8%)
Other Gas	13.6	0.0%	3.5	0.0%	(74.6%)
Hydroelectric	14,190.8	2.2%	13,415.7	2.1%	(5.5%)
Pumped Storage	4,497.7	0.7%	3,785.4	0.6%	(15.8%)
Run of River	8,196.3	1.3%	8,528.3	1.3%	4.1%
Other Hydro	1,496.9	0.2%	1,102.0	0.2%	(26.4%)
Wind	15,120.1	2.4%	16,973.8	2.7%	12.3%
Waste	3,356.8	0.5%	3,253.2	0.5%	(3.1%)
Solid Waste	3,155.7	0.5%	3,180.2	0.5%	0.8%
Miscellaneous	201.1	0.0%	73.0	0.0%	(63.7%)
Oil	3,066.6	0.5%	1,551.8	0.2%	(49.4%)
Heavy Oil	435.1	0.1%	101.6	0.0%	(76.6%)
Light Oil	899.9	0.1%	226.3	0.0%	(74.9%)
Diesel	358.8	0.1%	68.0	0.0%	(81.0%)
Gasoline	0.0	0.0%	0.0	0.0%	NA
Kerosene	58.8	0.0%	10.0	0.0%	(83.0%)
Jet Oil	8.0	0.0%	0.0	0.0%	(100.0%)
Other Oil	1,306.0	0.2%	1,145.8	0.2%	(12.3%)
Solar, Net Energy Metering	1,709.5	0.3%	2,260.3	0.4%	32.2%
Battery	10.6	0.0%	15.1	0.0%	42.7%
Biofuel	1,306.6	0.2%	1,017.9	0.2%	(22.1%)
Total	635,703.2	100.0%	634,231.2	100.0%	(0.2%)

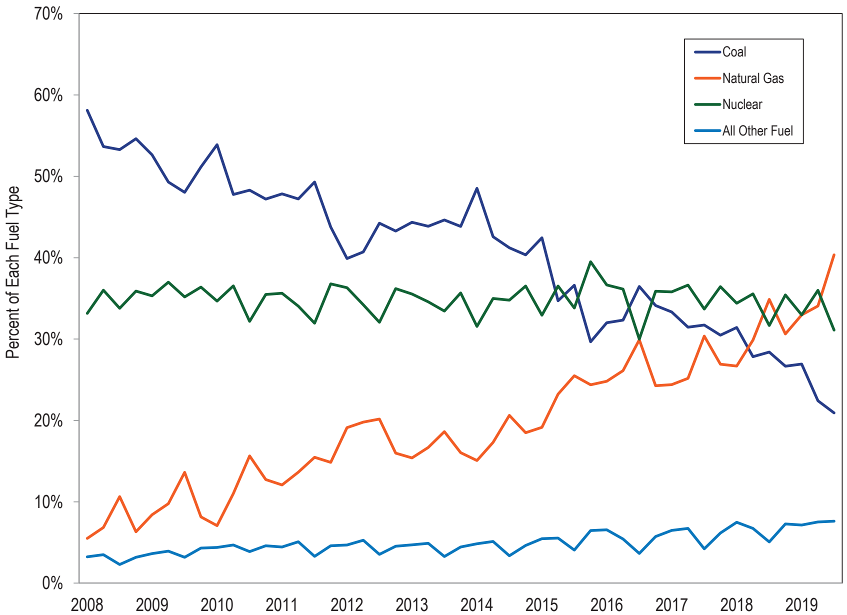
56 All generation is total gross generation output and does not net out the MWh withdrawn at a generation bus to provide auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps.
57 Net Energy Metering is combined with Solar due to data confidentiality reasons.
58 Other Gas includes: Propane, Butane, Hydrogen, Gasified Coal, and Refinery Gas. Other Coal includes: Lignite, Liquefied Coal, Gasified Coal, and Waste Coal.

Table 3-51 Monthly generation (By fuel source (GWh)): January through September, 2019

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Coal		23,151.4	16,444.7	17,418.6	12,890.6	14,846.9	15,112.1	21,599.4	17,945.8	15,898.9	155,308.3
	Bituminous	19,242.9	13,611.1	14,630.3	10,530.5	12,913.2	13,573.7	18,607.4	15,987.8	13,818.7	132,915.7
	Sub Bituminous	3,093.6	2,185.0	2,106.3	1,889.3	1,457.1	977.2	2,600.6	1,557.0	1,795.9	17,661.9
	Other Coal	814.9	648.6	682.0	470.8	476.6	561.2	391.4	401.0	284.2	4,730.8
Nuclear		25,595.0	22,303.6	21,899.6	21,078.7	23,997.8	23,735.1	24,670.8	24,471.5	22,790.6	210,542.6
Gas		23,457.9	23,274.3	23,627.3	19,184.6	20,646.8	25,825.1	34,360.8	32,346.0	27,169.7	229,892.5
	Natural Gas	23,265.9	23,104.3	23,443.2	19,012.7	20,465.9	25,651.6	34,177.6	32,164.6	26,996.8	228,282.7
	Landfill Gas	192.0	170.0	184.2	171.9	180.9	173.3	180.3	181.0	172.9	1,606.4
	Other Gas	0.0	0.0	0.0	0.0	0.0	0.2	2.9	0.4	0.0	3.5
Hydroelectric		1,805.1	1,453.6	1,699.3	1,593.8	1,742.6	1,523.0	1,518.7	1,185.9	893.5	13,415.7
	Pumped Storage	337.2	322.7	326.3	348.9	454.4	399.2	624.3	561.9	410.5	3,785.4
	Run of River	1,361.4	1,037.2	1,289.2	1,159.2	1,155.5	999.6	702.0	471.7	352.4	8,528.3
	Other Hydro	106.5	93.7	83.7	85.7	132.7	124.2	192.4	152.4	130.7	1,102.0
Wind		2,611.7	2,228.4	2,467.1	2,665.7	1,925.4	1,746.6	1,056.0	930.5	1,342.4	16,973.8
Waste		385.1	317.6	332.2	338.6	372.1	380.1	382.1	389.9	355.6	3,253.2
	Solid Waste	362.0	298.3	307.3	332.8	372.1	380.1	382.1	389.9	355.6	3,180.2
	Miscellaneous	23.0	19.3	24.9	5.7	0.0	0.0	0.0	0.0	0.0	73.0
Oil		214.5	127.2	145.4	99.1	169.0	152.3	265.8	251.1	127.4	1,551.8
	Heavy Oil	5.6	0.8	0.0	0.0	0.0	0.0	26.4	68.8	0.0	101.6
	Light Oil	41.8	15.0	13.5	4.6	8.6	4.6	85.5	27.1	25.6	226.3
	Diesel	15.5	4.6	41.9	1.2	1.2	0.7	1.4	1.2	0.4	68.0
	Gasoline	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Kerosene	9.7	0.1	0.0	0.0	0.0	0.1	0.0	0.1	0.0	10.0
	Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Other Oil	141.9	106.7	90.0	93.4	159.2	146.9	152.4	153.9	101.4	1,145.8
Solar, Net Energy Metering		130.1	145.8	230.4	254.5	293.2	295.6	344.6	300.0	266.1	2,260.3
Battery		2.0	2.0	2.2	1.9	1.7	1.3	1.6	1.3	1.3	15.1
Biofuel		107.3	80.7	108.3	96.1	98.5	101.4	143.9	140.2	141.7	1,017.9
Total		77,460.1	66,377.8	67,930.3	58,203.5	64,093.8	68,872.5	84,343.6	77,962.2	68,987.2	634,231.2

Figure 3-41 shows total generation percentage of natural gas, coal, nuclear and all other fuel types in the Real-Time Energy Market since 2008.

Figure 3-41 Generation by fuel source (Percentage): January 2008 through September 2019



Fuel Diversity

Figure 3-42 shows the fuel diversity index (FDI_e) for PJM energy generation.[59] 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 3-51 with nonzero generation values. As fuel diversity has increased, seasonality in the 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 38.6 percent from 2012 through 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.[60] 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 54.9 percent for 2008 and 24.5 percent for the first nine months of 2019. Gas generation as a share of total generation was 7.4 percent for 2008 and 36.2 percent for the first nine months of 2019. Wind generation as a share of total generation was 0.5 percent for 2008 and 2.7 percent for the first nine months of 2019.

The average FDI_e decreased 0.9 percent in the first nine months of 2019 compared to the first nine months in 2018. The FDI_e was also used to measure the impact on fuel diversity of potential retirements. Twenty-four coal units with installed capacity totaling 12,017 MW were identified as being at risk of retirement.[61] Generation owners that intend to retire a generator are required by the tariff to notify PJM at least 90 days in advance.[62] There are 8,093.7 MW of generation that have requested retirement after September 30, 2019.[63] The at risk units and other generators with deactivation notices generated 49.1 GWh in the first nine months of 2019. The dashed line in Figure 3-42 shows a counterfactual result for FDI_e assuming the 49.1 GWh of generation from at risk units and other generators with deactivation notices were replaced by gas generation. The average FDI_e for the first nine months of 2019 under the counterfactual assumption would have been 3.3 percent lower than the actual FDI_e.

59 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.

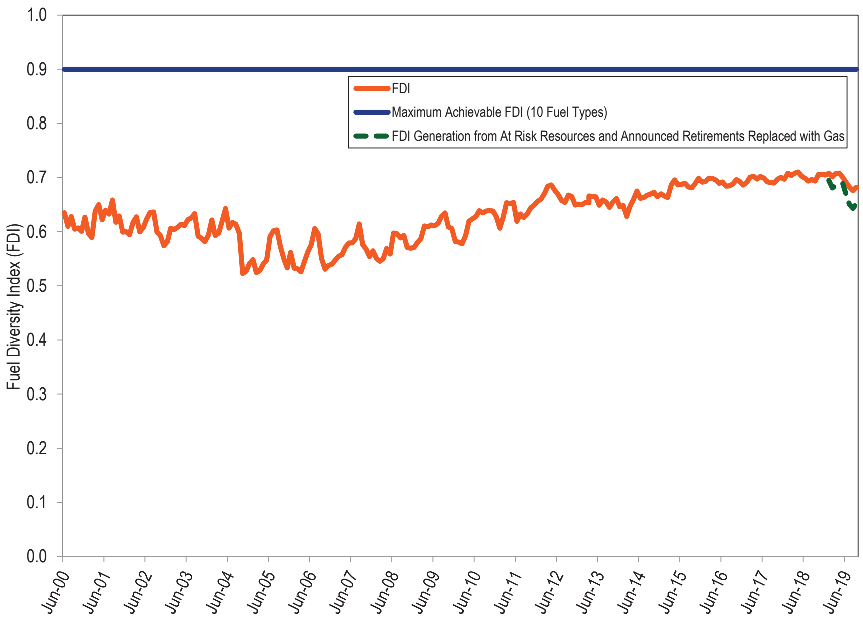
60 See the 2018 State of the Market Report for PJM, Volume 2, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton control zones occurred in October 2004.

61 See the 2018 State of the Market Report for PJM, Volume 2, Section 7: Net Revenue, Units at Risk. The list of at risk units has been updated to reflect the subsidies included in Ohio HB 6 which was passed by the Ohio legislature on July 23, 2019 <https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>.

62 See PJM. OATT: § V "Generation Deactivation."

63 Includes the generators in Table 12-9 plus four pseudo tied generators.

Figure 3-42 Fuel diversity index for monthly generation: June 2000 through September 2019



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 3-52 shows the type of fuel used and technology 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 2019, coal units were 27.2 percent and natural gas units were 69.7 percent of marginal resources. In the first nine months of 2019, natural gas combined cycle units were 62.2 percent of marginal resources. In the first nine months of 2018, coal units were 29.7 percent and natural gas units were 62.1 percent of the total marginal resources. In the first nine months of 2018, natural gas combined cycle units were 52.6 percent of the total marginal resources. In the first nine months of 2019, 92.9 percent of the wind marginal units had negative offer prices, 6.5 percent had zero offer prices and 0.6 percent had positive offer prices. 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.

The proportion of marginal nuclear units decreased from 1.06 percent in the first nine months of 2018 to 0.81 percent in the first nine months of 2019. 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 2015. The dispatchable nuclear units do not always respond to dispatch instructions.

Table 3-52 Type of fuel used and technology (By real-time marginal units): January through September, 2015 through 2019[64]

		(Jan - Sep)				
Fuel	Technology	2015	2016	2017	2018	2019
Gas	CC	28.75%	29.25%	44.63%	52.58%	62.16%
Coal	Steam	54.45%	46.21%	32.28%	29.71%	27.17%
Gas	CT	3.98%	7.05%	4.70%	7.19%	5.87%
Wind	Wind	2.74%	2.67%	7.28%	2.78%	1.66%
Gas	Steam	3.77%	5.01%	3.53%	1.91%	1.34%
Uranium	Steam	0.03%	0.92%	1.23%	1.06%	0.81%
Oil	CT	3.35%	7.51%	5.18%	2.88%	0.46%
Gas	RICE	0.06%	0.10%	0.39%	0.42%	0.31%
Other	Steam	0.42%	0.12%	0.19%	0.19%	0.08%
Oil	RICE	1.54%	0.96%	0.26%	0.52%	0.06%
Oil	Steam	0.17%	0.05%	0.05%	0.39%	0.04%
Other	Solar	0.01%	0.03%	0.18%	0.09%	0.02%
Landfill Gas	Steam	0.01%	0.03%	0.05%	0.00%	0.01%
Landfill Gas	CT	0.00%	0.01%	0.01%	0.02%	0.01%
Oil	CC	0.62%	0.03%	0.01%	0.17%	0.01%
Landfill Gas	RICE	0.01%	0.05%	0.01%	0.04%	0.01%
Municipal Waste	Steam	0.06%	0.01%	0.01%	0.04%	0.00%
Gas	Fuel Cell	0.04%	0.00%	0.00%	0.00%	0.00%

64 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Figure 3-43 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 3-43 Type of fuel used (By real-time marginal units): January through September, 2004 through 2019

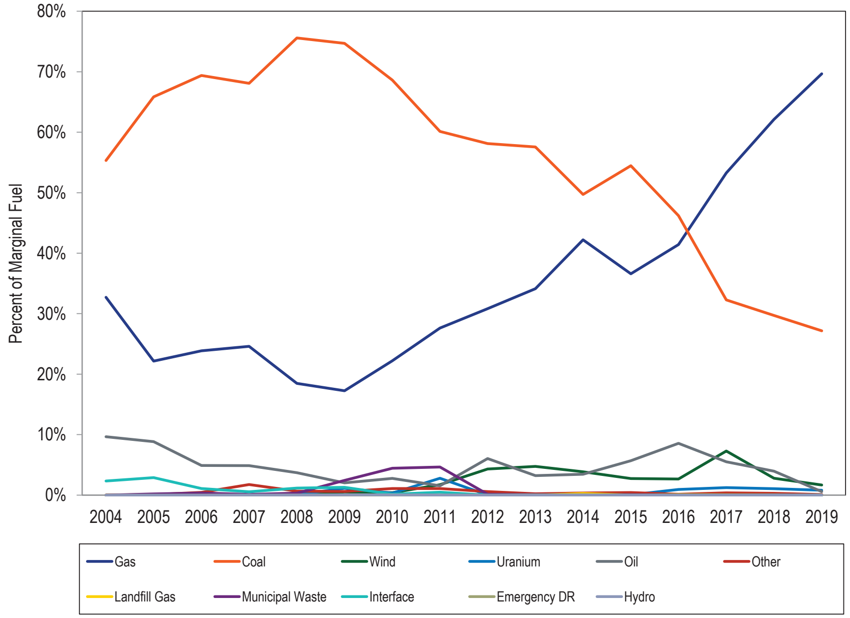


Table 3-53 shows the type of fuel used and technology where relevant, of marginal resources in the Day-Ahead Energy Market. In the first nine months of 2019, up to congestion transactions were 57.7 percent of marginal resources. Up to congestion transactions were 63.9 percent of marginal resources in the first nine months of 2018.

Table 3-53 Day-ahead marginal resources by type/fuel used and technology: January through September, 2011 through 2019

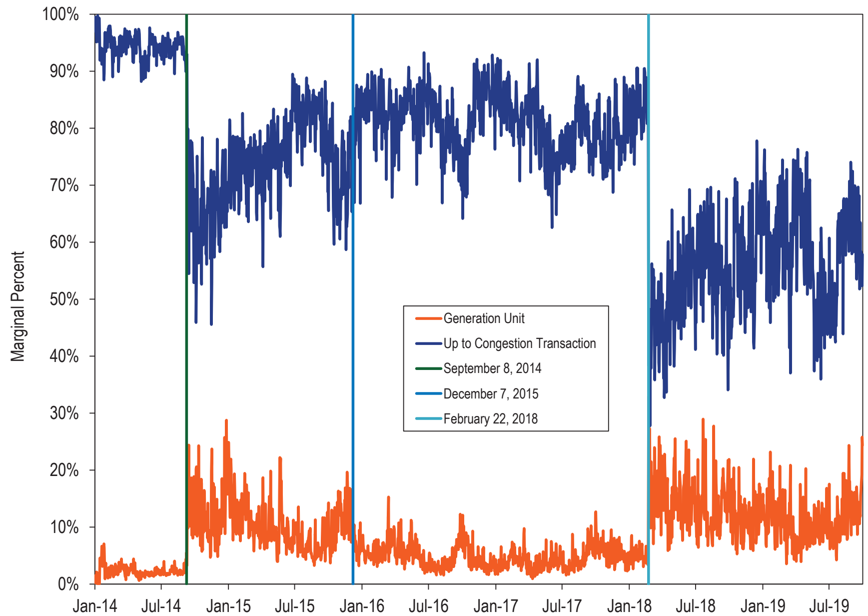
		(Jan - Sep)								
Type/Fuel	Technology	2011	2012	2013	2014	2015	2016	2017	2018	2019
Up to Congestion Transaction	NA	68.53%	86.21%	95.96%	93.09%	74.65%	81.19%	79.84%	63.90%	57.70%
DEC	NA	14.22%	5.12%	1.24%	2.17%	8.38%	8.82%	10.03%	16.06%	18.41%
INC	NA	8.33%	4.34%	1.00%	1.58%	4.83%	4.22%	5.49%	9.24%	12.86%
Gas	Steam	2.12%	1.40%	0.54%	1.25%	3.96%	2.52%	2.30%	5.32%	6.23%
Coal	Steam	6.06%	2.66%	1.13%	1.71%	7.15%	2.42%	1.74%	4.57%	4.23%
Gas	CT	0.14%	0.09%	0.01%	0.05%	0.32%	0.11%	0.10%	0.29%	0.18%
Dispatchable Transaction	NA	0.23%	0.07%	0.06%	0.08%	0.30%	0.05%	0.03%	0.13%	0.10%
Wind	Wind	0.07%	0.04%	0.04%	0.03%	0.14%	0.04%	0.17%	0.16%	0.10%
Uranium	Steam	0.00%	0.00%	0.00%	0.00%	0.00%	0.09%	0.06%	0.12%	0.06%
Oil	CT	0.00%	0.00%	0.00%	0.00%	0.16%	0.52%	0.19%	0.04%	0.04%
Gas	RICE	0.00%	0.01%	0.00%	0.00%	0.00%	0.01%	0.02%	0.05%	0.04%
Other	Solar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.03%	0.02%
Other	Steam	0.00%	0.00%	0.00%	0.00%	0.02%	0.01%	0.00%	0.01%	0.01%
Municipal Waste	RICE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%
Oil	Steam	0.01%	0.01%	0.00%	0.02%	0.02%	0.00%	0.00%	0.07%	0.01%
Price Sensitive Demand	NA	0.27%	0.05%	0.01%	0.01%	0.03%	0.00%	0.00%	0.02%	0.00%
Oil	RICE	0.00%	0.00%	0.00%	0.00%	0.04%	0.00%	0.01%	0.00%	0.00%
Municipal Waste	Steam	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Water	Hydro	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%	0.00%
Municipal Waste	CT	0.00%	0.00%	0.00%	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%	100.00%

Figure 3-44 shows, for the Day-Ahead Energy Market from January 2014 through September 2019, 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.[65] That trend reversed as a result of the expiration of the 15 month uplift refund period for UTC transactions. But in February 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.[66] The order limited UTC trading to hubs, residual metered load, and interfaces. The share of marginal UTCs decreased from 63.9 percent in the first nine months of 2018 to 57.7 percent in the first nine months of 2019.

The average number of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 24.9 percent, from 68,693 bids per day in the first nine months of 2018 to 51,594 bids per day in the first nine months of 2019. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market increased by 15.9 percent, from 423,268 MWh per day in the first nine months of 2018, to 490,421 MWh per day in the first nine months of 2019.

65 See 18 CFR § 385.213 (2014).
66 162 FERC ¶ 61,139 (2018).

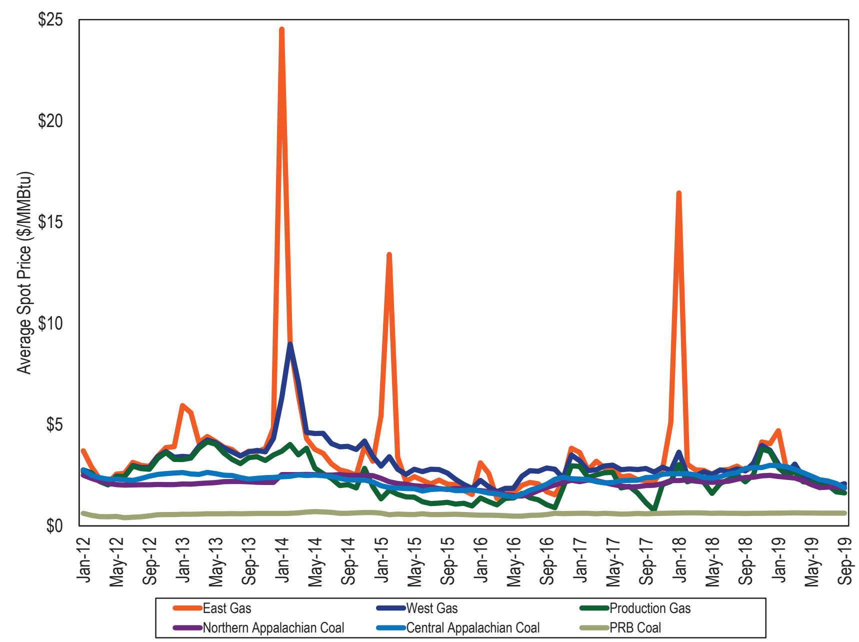
Figure 3-44 Day-ahead marginal up to congestion transaction and generation units: January 2014 through September 2019



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. Gas prices fell in the first nine months of 2019 compared to the first nine months of 2018. Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. Natural gas prices decreased in the first nine months of 2019 compared to the first nine months of 2018. The price of natural gas in the Marcellus Shale production area is lower than in other areas of PJM. A number of new combined cycle plants have located in the production area since 2016. In the first nine months of 2019, the price of production gas was 3.3 percent lower than in the first nine months of 2018. The price of eastern natural gas was 39.6 percent lower and the price of western natural gas was 12.7 percent lower. (Figure 3-45) The price of Northern Appalachian coal was 5.2 percent lower; the price of Central Appalachian coal was 2.9 percent lower; and the price of Powder River Basin coal was 0.6 percent higher.[67]

Figure 3-45 Spot average fuel price comparison: January 2012 through September 2019 ($/MMBtu)



67 Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily indices. Western natural gas prices are the average of Columbia Appalachia and Chicago Citygate daily indices. Production gas prices are the average of Dominion South Point, Tennessee Zone 4, and Transco Leidy Line receipts daily 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.

Table 3-54 compares the first nine months of 2019 PJM real-time fuel-cost adjusted, load-weighted, average LMP to the first nine months of 2019 load-weighted, average LMP.[68] The real-time, load-weighted average LMP for the first nine months of 2019 decreased by $11.83 or -30.0 percent from real-time load-weighted, average LMP for the first nine months of 2018. The real-time load-weighted, average LMP for the first nine months of 2019 was 12.8 percent lower than the real-time fuel-cost adjusted, load-weighted average LMP for the first nine months of 2019. The real-time, fuel-cost adjusted, load-weighted average LMP for the first nine months of 2019 was 19.7 percent lower than the real-time load-weighted, average LMP for the first nine months of 2018. If fuel and emissions costs in the first nine months of 2019 had been the same as in the first nine month of 2018, holding everything else constant, the real-time, load-weighted, average LMP in the first nine months of 2019 would have been higher, $31.65 per MWh, than the observed $27.60 per MWh. Only 34 percent of the decrease in real-time, load-weighted, average LMP, $4.05 per MWh out of $11.83 per MWh, is directly attributable to fuel costs. Contributors to the other $7.78 per MWh are decreased load, increased supply, adjusted dispatch, and lower markups.

Table 3-54 Real-time, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): January through September, 2018 and 2019

	2019 Fuel-Cost Adjusted, Load-Weighted LMP	2019 Load-Weighted LMP	Change	Percent Change
Average	$31.65	$27.60	($4.05)	(12.8%)
	2018 Load-Weighted LMP	2019 Fuel-Cost Adjusted, Load-Weighted LMP	Change	Percent Change
Average	$39.43	$31.65	($7.78)	(19.7%)
	2018 Load-Weighted LMP	2019 Load-Weighted LMP	Change	Change
Average	$39.43	$27.60	($11.83)	(30.0%)

Table 3-55 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 2019. Table 3-55 shows that lower natural gas prices explain all of the fuel-cost related decrease in the real-time annual, load-weighted average LMP in the first nine months of 2019 from the first nine months of 2018.

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

Table 3-55 Change in real-time, fuel-cost adjusted, load-weighted average LMP ($/MWh) by fuel type: January through September, 2018 to 2019

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Other	$0.00	0.0%
Uranium	$0.00	0.0%
Municipal Waste	$0.00	0.0%
Wind	$0.00	0.0%
Oil	($0.01)	0.1%
Coal	($0.10)	2.5%
Gas	($3.95)	97.4%
NA	$0.00	0.0%
Total	($4.05)	100.0%

Table 3-56 shows the first nine months of 2019 PJM real-time fuel-cost adjusted, load-weighted, average LMP using the first nine months of 2018, 2017, 2016, and 2015 fuel and emission costs. If fuel and emissions costs in the first nine months of 2019 had been the same as in first nine months of 2015, holding everything else constant, the real-time load-weighted LMP in the first nine months of 2019 would have been higher, $28.35 per MWh, than the observed $27.60 per MWh. If only fuel and emission costs of natural gas units in the first nine months of 2019 had been the same as in the first nine months of 2015, holding everything else constant, the real-time load-weighted LMP in the first nine months of 2019 would have been higher, $28.70 per MWh, than the observed $27.60 per MWh.

Table 3-56 Historical Real-time, fuel-cost adjusted, load-weighted average LMP by Fuel Type (Dollars per MWh): January through September, 2015 through 2019

	2019 Fuel-Cost Adjusted, Load Weighted LMP			
	All Units	Gas Units	Coal Units	Oil Units
2019 Fuel and Emission Costs	$27.60	$27.60	$27.60	$27.60
2018 Fuel and Emission Costs	$31.65	$31.55	$27.70	$27.61
2017 Fuel and Emission Costs	$28.21	$28.36	$27.46	$27.59
2016 Fuel and Emission Costs	$25.01	$25.62	$27.00	$27.59
2015 Fuel and Emission Costs	$28.35	$28.70	$27.26	$27.59

Components of LMP

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.[69] 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 the SCED solution does not meet the reserve requirements, PJM should invoke shortage pricing. During shortage conditions, the LMPs of marginal generators reflect the cost of not meeting the reserve requirements, the scarcity adder, which is defined by the operating reserve demand curve.

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

Table 3-59 shows the frequency and average shadow price of transmission constraints in PJM. In the first nine months of 2019, there were 96,836 transmission constraint intervals in the real-time market with a nonzero shadow price. For nearly 5 percent of these transmission constraint intervals, the line limit was violated, meaning that the flow exceeded the facility limit.[70] In the first nine months of 2019, the average shadow price of transmission constraints when the line limit was violated was nearly fourteen 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 had been using 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 factors have not directly set the shadow price through 2018. In 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 recommended 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. PJM adopted the MMU's recommendation to remove the constraint relaxation logic and

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

70 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.

allow transmission penalty factors to set prices in the day-ahead and real-time markets for all internal transmission constraints. PJM also revised the tariff to list the conditions under which transmission penalty factors would be changed from their default value of $2,000 per MWh. The new rules went into effect on February 1, 2019. PJM has not yet adopted the same MMU recommendation for reciprocally coordinated market to market constraints with neighboring RTOs. PJM continues the practice of discretionary reduction in line ratings.

Table 3-60 shows the frequency of changes to the magnitude of transmission penalty factor of binding and violated transmission constraints in the PJM real-time market. In the first nine months of 2019, there were 3,203 or 69 percent of internal violated transmission constraint intervals in the real-time market with transmission penalty factor equal to the default $2,000 per MWh. In the first nine months of the 2019, there were 1,380 or 30 percent of internal violated transmission constraint intervals in the real-time market with transmission penalty factor below the default, $2,000 per MWh.

The components of LMP are shown in Table 3-57, including markup using unadjusted cost-based offers.[71] Table 3-57 shows that in the first nine months of 2019, 26.8 percent of the load-weighted LMP was the result of coal costs, 42.7 percent was the result of gas costs and 0.87 percent was the result of the cost of emission allowances. Using adjusted cost-based offers, markup was 14.7 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 2019, nearly 14 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 2019 and 2018.

71 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 3-57 Components of real-time (Unadjusted), load-weighted, average LMP: January through September, 2018 and 2019

	2018 (Jan - Sep)		2019 (Jan - Sep)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Gas	$15.51	39.3%	$11.79	42.7%	3.4%
Coal	$7.84	19.9%	$7.40	26.8%	6.9%
Ten Percent Adder	$2.76	7.0%	$2.12	7.7%	0.7%
Markup	$5.17	13.1%	$1.95	7.1%	(6.0%)
VOM	$1.48	3.8%	$1.69	6.1%	2.4%
Increase Generation Adder	$0.92	2.3%	$1.42	5.1%	2.8%
NA	$2.11	5.3%	$0.32	1.1%	(4.2%)
Scarcity Adder	$0.03	0.1%	$0.26	1.0%	0.9%
CO_2 Cost	$0.12	0.3%	$0.22	0.8%	0.5%
Ancillary Service Redispatch Cost	$0.41	1.0%	$0.21	0.7%	(0.3%)
LPA Rounding Difference	$0.65	1.6%	$0.14	0.5%	(1.1%)
Opportunity Cost Adder	$0.08	0.2%	$0.09	0.3%	0.1%
Oil	$2.23	5.7%	$0.06	0.2%	(5.5%)
NO_x Cost	$0.11	0.3%	$0.02	0.1%	(0.2%)
Constraint Violation Adder	($0.00)	(0.0%)	$0.01	0.0%	0.0%
Other	$0.07	0.2%	$0.00	0.0%	(0.2%)
Market-to-Market Adder	$0.01	0.0%	$0.00	0.0%	(0.0%)
SO_2 Cost	$0.01	0.0%	$0.00	0.0%	(0.0%)
Landfill Gas	$0.00	0.0%	$0.00	0.0%	0.0%
Uranium	($0.00)	(0.0%)	$0.00	0.0%	0.0%
Municipal Waste	$0.13	0.3%	$0.00	0.0%	(0.3%)
Wind	($0.01)	(0.0%)	$0.00	0.0%	0.0%
LPA-SCED Differential	($0.02)	(0.1%)	($0.01)	(0.0%)	0.0%
Renewable Energy Credits	($0.04)	(0.1%)	($0.02)	(0.1%)	0.0%
Decrease Generation Adder	($0.13)	(0.3%)	($0.06)	(0.2%)	0.1%
Total	$39.43	100.0%	$27.60	100.0%	0.0%

In order to accurately assess the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach (Table 3-57 and Table 3-61), markup is simply the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-58 and Table 3-62), 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 3-58, including markup using adjusted cost-based offers.

Table 3-58 Components of real-time (Adjusted), load-weighted, average LMP: January through September, 2018 and 2019

	2018 (Jan - Sep)		2019 (Jan - Sep)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Gas	$15.51	39.3%	$11.79	42.7%	3.4%
Coal	$7.84	19.9%	$7.40	26.8%	6.9%
Markup	$7.90	20.0%	$4.07	14.7%	(5.3%)
VOM	$1.48	3.8%	$1.69	6.1%	2.4%
Increase Generation Adder	$0.92	2.3%	$1.42	5.1%	2.8%
NA	$2.11	5.3%	$0.32	1.1%	(4.2%)
Scarcity Adder	$0.03	0.1%	$0.26	1.0%	0.9%
CO_2 Cost	$0.12	0.3%	$0.22	0.8%	0.5%
Ancillary Service Redispatch Cost	$0.41	1.0%	$0.21	0.7%	(0.3%)
LPA Rounding Difference	$0.65	1.6%	$0.14	0.5%	(1.1%)
Opportunity Cost Adder	$0.08	0.2%	$0.09	0.3%	0.1%
Oil	$2.23	5.7%	$0.06	0.2%	(5.5%)
NO_x Cost	$0.11	0.3%	$0.02	0.1%	(0.2%)
Constraint Violation Adder	($0.00)	(0.0%)	$0.01	0.0%	0.0%
Other	$0.07	0.2%	$0.00	0.0%	(0.2%)
Market-to-Market Adder	$0.01	0.0%	$0.00	0.0%	(0.0%)
Ten Percent Adder	$0.02	0.1%	$0.00	0.0%	(0.0%)
SO_2 Cost	$0.01	0.0%	$0.00	0.0%	(0.0%)
Landfill Gas	$0.00	0.0%	$0.00	0.0%	0.0%
Uranium	($0.00)	(0.0%)	$0.00	0.0%	0.0%
Municipal Waste	$0.13	0.3%	$0.00	0.0%	(0.3%)
Wind	($0.01)	(0.0%)	$0.00	0.0%	0.0%
LPA-SCED Differential	($0.02)	(0.1%)	($0.01)	(0.0%)	0.0%
Renewable Energy Credits	($0.04)	(0.1%)	($0.02)	(0.1%)	0.0%
Decrease Generation Adder	($0.13)	(0.3%)	($0.06)	(0.2%)	0.1%
Total	$39.43	100.0%	$27.60	100.0%	0.0%

Table 3-59 Frequency and average shadow price of transmission constraints: January through September, 2018 and 2019

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2018 (Jan - Sep)	2019 (Jan - Sep)	2018 (Jan - Sep)	2019 (Jan - Sep)
PJM Internal Violated Transmission Constraints	10,539	4,653	$1,307.70	$1,488.52
PJM Internal Binding Transmission Constraints	71,036	59,363	$198.67	$100.08
Market to Market Transmission Constraints	37,027	32,820	$424.61	$233.61
All Transmission Constraints	118,602	96,836	$367.76	$212.05

Table 3-60 Frequency of changes to the magnitude of transmission penalty factor (constraint intervals): January through September, 2018 and 2019

	2018 (Jan - Sep)			2019 (Jan - Sep)		
Description	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh
PJM Internal Violated Transmission Constraints	6,535	1,193	2,811	3,203	70	1,380
PJM Internal Binding Transmission Constraints	59,830	4,369	6,837	56,230	696	2,437
Market to Market Transmission Constraints	12,631	53	24,343	6,557	3	26,260
All Transmission Constraints	78,996	5,615	33,991	65,990	769	30,077

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 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.[72] Day-ahead scheduling reserve (DASR), lost opportunity cost (LOC) and DASR offer adders are the calculated contribution to LMP when redispatch of resources is needed in order to satisfy DASR requirements.

Table 3-61 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In the first nine months of 2019, 22.2 percent of the load-weighted LMP was the result of coal costs, 19.8 percent of the load-weighted LMP was the result of gas costs, 21.2 percent was the result of DEC bid costs, 21.3 percent was the result of INC bid costs and 2.2 percent was the result of the up to congestion transaction costs.

Table 3-61 Components of day-ahead, (unadjusted), load-weighted, average LMP (Dollars per MWh): January through September, 2018 and 2019

	2018 (Jan - Sep)		2019 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$6.40	16.5%	$6.14	22.2%	5.6%
INC	$7.01	18.1%	$5.90	21.3%	3.2%
DEC	$11.30	29.2%	$5.86	21.2%	(8.0%)
Gas	$6.93	17.9%	$5.48	19.8%	1.9%
Ten Percent Cost Adder	$1.57	4.1%	$1.30	4.7%	0.6%
VOM	$1.04	2.7%	$1.22	4.4%	1.7%
Markup	$1.26	3.3%	$0.67	2.4%	(0.9%)
Up to Congestion Transaction	$1.15	3.0%	$0.62	2.2%	(0.7%)
Dispatchable Transaction	$0.49	1.3%	$0.33	1.2%	(0.1%)
CO_2	$0.07	0.2%	$0.14	0.5%	0.3%
Oil	$1.17	3.0%	$0.02	0.1%	(2.9%)
NO_x	$0.09	0.2%	$0.01	0.1%	(0.2%)
Price Sensitive Demand	$0.06	0.1%	$0.01	0.1%	(0.1%)
Other	($0.00)	(0.0%)	$0.01	0.0%	0.0%
DASR Offer Adder	($0.03)	(0.1%)	$0.00	0.0%	0.1%
DASR LOC Adder	$0.17	0.4%	$0.00	0.0%	(0.4%)
Constrained Off	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2	$0.01	0.0%	$0.00	0.0%	(0.0%)
Municipal Waste	$0.00	0.0%	$0.00	0.0%	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%	(0.0%)
Wind	($0.01)	(0.0%)	($0.02)	(0.1%)	(0.0%)
Total	$38.70	100.0%	$27.70	100.0%	0.0%

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

Table 3-62 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 3-62 Components of day-ahead, (adjusted), load-weighted, average LMP (Dollars per MWh): January through September, 2018 and 2019

	2018 (Jan - Sep)		2019 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$6.40	16.5%	$6.14	22.2%	5.6%
INC	$7.01	18.1%	$5.90	21.3%	3.2%
DEC	$11.30	29.2%	$5.86	21.2%	(8.0%)
Gas	$6.93	17.9%	$5.48	19.8%	1.9%
Markup	$2.81	7.3%	$1.95	7.0%	(0.2%)
VOM	$1.04	2.7%	$1.22	4.4%	1.7%
Up to Congestion Transaction	$1.15	3.0%	$0.62	2.2%	(0.7%)
Dispatchable Transaction	$0.49	1.3%	$0.33	1.2%	(0.1%)
CO_2	$0.07	0.2%	$0.14	0.5%	0.3%
Oil	$1.17	3.0%	$0.02	0.1%	(2.9%)
Ten Percent Cost Adder	$0.03	0.1%	$0.02	0.1%	0.0%
NO_x	$0.09	0.2%	$0.01	0.1%	(0.2%)
Price Sensitive Demand	$0.06	0.1%	$0.01	0.1%	(0.1%)
Other	($0.00)	(0.0%)	$0.01	0.0%	0.0%
DASR Offer Adder	($0.03)	(0.1%)	$0.00	0.0%	0.1%
DASR LOC Adder	$0.17	0.4%	$0.00	0.0%	(0.4%)
Constrained Off	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2	$0.01	0.0%	$0.00	0.0%	(0.0%)
Municipal Waste	$0.00	0.0%	$0.00	0.0%	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%	(0.0%)
Wind	($0.01)	(0.0%)	($0.02)	(0.1%)	(0.0%)
Total	$38.70	100.0%	$27.70	100.0%	0.0%

Scarcity

PJM's energy market experienced five minute shortage pricing for 27 intervals on fourteen days in the first nine months of 2019. Table 3-63 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in the first nine months of 2018 and 2019.

Table 3-63 Summary of emergency events declared: January through September, 2018 and 2019

	Number of days events declared	
Event Type	Jan -Sep, 2018	Jan - Sep, 2019
Cold Weather Alert	12	9
Hot Weather Alert	23	15
Maximum Emergency Generation Alert	0	0
Primary Reserve Alert	0	0
Voltage Reduction Alert	0	0
Primary Reserve Warning	0	0
Voltage Reduction Warning	0	0
Pre Emergency Mandatory Load Management Reduction Action	0	0
Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time)	0	0
Maximum Emergency Action	0	0
Emergency Energy Bids Requested	0	0
Voltage Reduction Action	0	0
Shortage Pricing	0	14
Energy export recalls from PJM capacity resources	0	0

Figure 3-46 shows the number of days that weather and capacity emergency alerts were issued in PJM in the first nine months from 2015 through 2019. Figure 3-47 shows the number of days emergency warnings were issued and actions were taken in PJM in the first nine months from 2015 through 2019.

Figure 3-46 Declared emergency alerts: January through September, 2015 through 2019

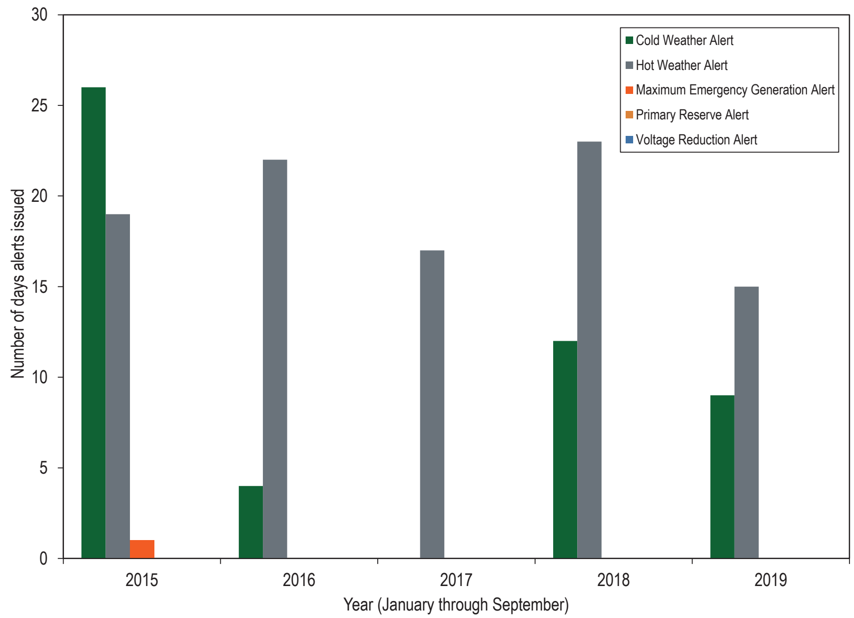
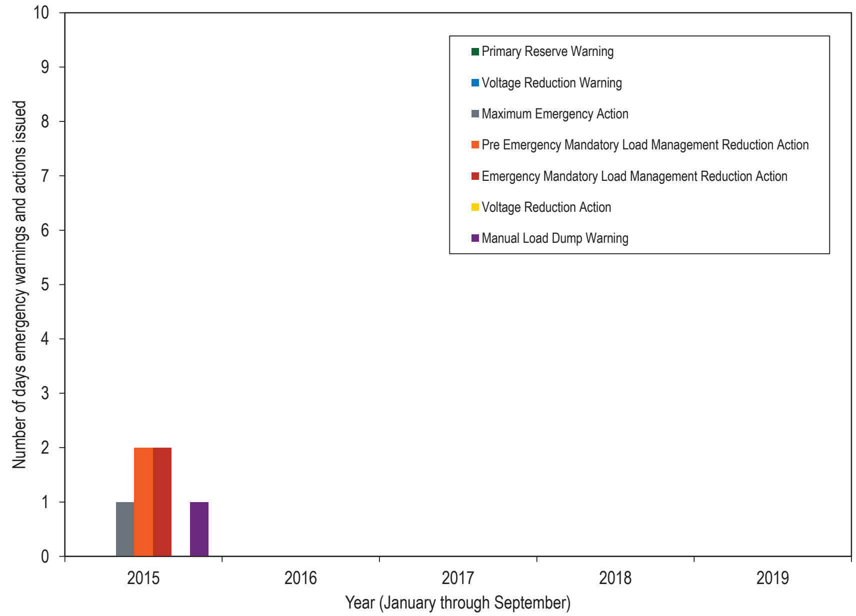


Figure 3-47 Declared emergency warnings and actions: January through September, 2015 through 2019



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.

Table 3-64 provides a description of PJM declared emergency procedures.[73] [74] [75] [76]

Table 3-64 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.

73 See PJM. "Manual 13: Emergency Operations," Rev. 72 (Sep. 26, 2019), Section 3.3 Cold Weather Alert.
74 See PJM. "Manual 13: Emergency Operations," Rev. 72 (Sep 26, 2019), Section 3.4 Hot Weather Alert.
75 See PJM. "Manual 13: Emergency Operations," Rev. 72 (Sep. 26, 2019), Section 2.3.1 Advanced Notice Emergency Procedures: Alerts.
76 See PJM. "Manual 13: Emergency Operations," Rev. 72 (Sep. 26, 2019), 2.3.2 Real-Time Emergency Procedures (Warnings and Actions).

Table 3-65 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in the first nine months of 2019.

Table 3-65 Declared emergency alerts, warnings and actions: January through September, 2019

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
1/20/2019	Western													
1/21/2019	PJM RTO													
1/22/2019	PJM RTO													
1/25/2019	Western													
1/29/2019	ComEd													
1/30/2019	Western													
1/31/2019	PJM RTO													
2/1/2019	PJM RTO													
3/4/2019	ComEd													
6/27/2019		Mid Atlantic and Southern												
6/28/2019		Mid Atlantic and Southern												
6/29/2019		Mid Atlantic and Southern												
7/17/2019		Mid Atlantic and Dominion												
7/18/2019		PJM RTO												
7/19/2019		PJM RTO												
7/20/2019		PJM RTO												
7/21/2019		PJM RTO except ComEd												
7/29/2019		Mid Atlantic												
7/30/2019		Mid Atlantic												
8/18/2019		Mid Atlantic and Western except ComEd												
8/19/2019		PJM RTO except ComEd												
8/20/2019		Mid Atlantic and Dominion												
8/21/2019		Mid Atlantic												
9/12/2019		PJM RTO												

PAIs and Capacity Performance

In the first nine months of 2019, PJM did not declare any emergency actions that triggered Performance Assessment Intervals (PAIs). In 2018, PJM declared two localized load shed events in the AEP Zone, in the Twin Branch - Edison area and Lonesome Pine – Bluefield area. 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. Scarcity pricing is a mechanism for signaling scarcity conditions through energy prices. Under the PJM rules that were in place through September 30, 2012, 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. Shortage pricing is an administrative scarcity pricing mechanism in which PJM sets a high energy price at a predetermined level when the system operates with less real time reserves than required.

In the first nine months of 2019, there were 27 five minute intervals with shortage pricing that occurred on fourteen days in PJM.

With Order No. 825, 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.[77] 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) reflected 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.

Voltage reduction actions and manual load dump actions are also triggers for shortage pricing, reflecting the fact that when operators need to take these emergency actions to maintain reliability, the system is short reserves and

77 *Id* at P 162.

prices should reflect that condition, even if the data does not show a shortage of reserves.[78]

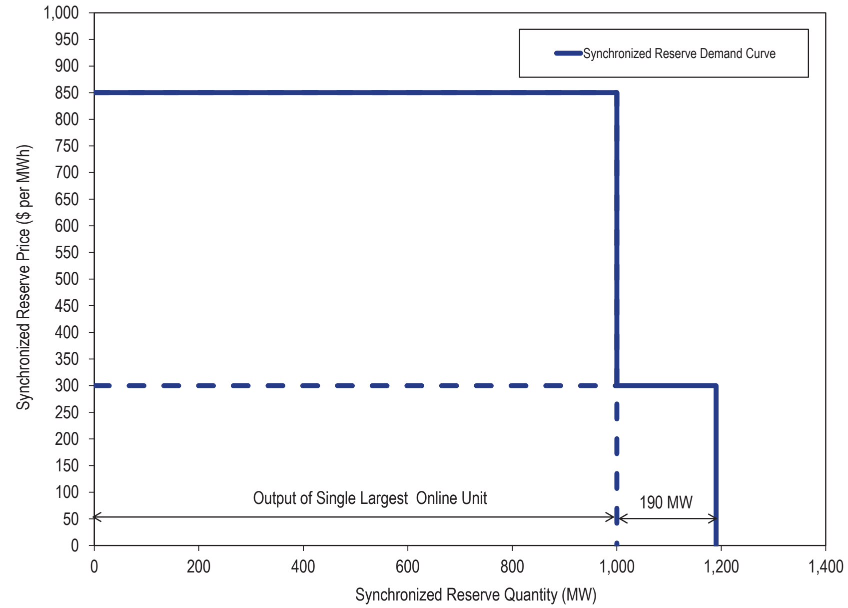
PJM Tariff Revisions to Operating Reserve Demand Curves

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.[79] 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 3-48 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.

78 *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).
79 See PJM Filing, FERC Docket No. ER17-1590-000 (May 12, 2017).

Figure 3-48 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 define an administrative price for estimated reserves (primary and synchronized reserves) up to the extended reserve requirement quantities. The demand curve shown in Figure 3-48 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.

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 when 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 other 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 correctly 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 reserve 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.

Reserve Shortages in 2019

Reserve Shortage in Real-Time SCED

The MMU analyzed the RT SCED solved cases to determine how many of the solved RT SCED cases indicated a shortage of any of the reserve products (synchronized reserve and primary reserve at RTO reserve zone and MAD reserve subzone), how many of these solved cases were approved by PJM, and how many of these were used in LPC to calculate prices. Reserves are considered short if the quantity (MW) of reserves dispatched by RT SCED for a five minute interval was less than the extended reserve requirement. Table 3-66 shows the number and percent of RT SCED cases solved that indicated a shortage of any of the four reserve products (RTO synchronized reserve, RTO primary reserve, MAD synchronized reserve, and MAD primary reserve), the number and percent of the solved RT SCED cases with shortage that were approved by PJM, and the number and percent of the RT SCED cases with shortage that were used in LPC to calculate real-time prices. Table 3-66 shows that, in the first nine months of 2019, PJM operators approved 35 RT SCED cases that indicated a shortage of reserves, from a total of 4,166 RT SCED solutions that indicated shortage. Among the 35 approved cases, only 25 cases were used in LPC to calculate LMPs and reserve clearing prices. In comparison, in the first nine months of 2018, PJM operators approved only five cases that indicated a shortage of reserves, from a total of 5,484 RT SCED solutions that indicated shortage. While the fraction of SCED solutions with shortage decreased from 1.2 percent in the first nine months of 2018 to 0.9 percent in the first nine months of 2019, the fraction of solved SCED cases with shortage that were approved by PJM operators increased from 0.1 percent in the first nine months of 2018 to 0.8 percent in the first nine months of 2019. It is unclear what criteria PJM operators use to approve the RT SCED cases to send dispatch signals to resources.

Table 3-66 RT SCED cases with reserve shortage: January through September, 2019

Month (2019)	Number of Solved RT SCED Cases	Number of Solved RT SCED Cases With Reserve Shortage	Number of Approved RT SCED Cases With Reserve Shortage	Number of Approved RT SCED Cases With Reserve Shortage Used in LPC	Cases With Reserve Shortage as Percent of Solved RT SCED Cases	Approved RT SCED Cases With Reserve Shortage as Percent of Solved RT SCED Cases With Shortage	RT SCED Cases With Shortage Used in LPC as Percent of Solved RT SCED Cases With Shortage
Jan	49,158	151	3	3	0.3%	2.0%	2.0%
Feb	43,628	317	0	0	0.7%	0.0%	0.0%
Mar	49,753	713	16	10	1.4%	2.2%	1.4%
Apr	48,765	796	9	6	1.6%	1.1%	0.8%
May	50,772	364	0	0	0.7%	0.0%	0.0%
Jun	51,299	377	0	0	0.7%	0.0%	0.0%
Jul	50,011	544	3	3	1.1%	0.6%	0.6%
Aug	50,769	379	0	0	0.7%	0.0%	0.0%
Sep	49,276	525	4	3	1.1%	0.8%	0.6%
Total	443,431	4,166	35	25	0.9%	0.8%	0.6%

While there were 4,166 solved RT SCED cases that indicated shortage, the number of five minute intervals where RT SCED indicated shortage was only 2,307. This is because PJM solves multiple RT SCED cases for each five minute target interval.[80]

The MMU analyzed the intervals where one or more solved RT SCED cases indicated a shortage of one or more reserve products. Table 3-67 shows, for each month in the first nine months of 2019, the total number of five minute intervals, the number of intervals where at least one solved SCED case showed a shortage of reserves, the number of intervals where more than one solved SCED case showed a shortage of reserves, and the number of five minute intervals where the LPC solution showed a shortage of reserves. Table 3-67 shows that 2,307 intervals, or 2.9 percent of all five minute intervals in the first nine months of 2019 had at least one solved SCED case showing a shortage of reserves, and 1,045 intervals, or 1.3 percent of all five minute intervals in the first nine months of 2019 had more than one solved SCED case showing a shortage of reserves.

Table 3-67 Five minute intervals with shortage: January through September, 2019

Month (2019)	Number of Five Minute Intervals	Number of Intervals With At Least One Solved SCED Case Short of Reserves	Percent Intervals With At Least One Solved SCED Case Short of Reserves	Number of Intervals With Multiple Solved SCED Cases Short of Reserves	Percent Intervals With Multiple Solved SCED Cases Short of Reserves	Number of Intervals With Five Minute Shortage Prices in LPC	Percent Intervals With Five Minute Shortage Prices in LPC
Jan	8,928	87	1.0%	34	0.4%	3	0.0%
Feb	8,064	185	2.3%	79	1.0%	0	0.0%
Mar	8,916	350	3.9%	175	2.0%	10	0.1%
Apr	8,640	424	4.9%	217	2.5%	7	0.1%
May	8,928	203	2.3%	94	1.1%	0	0.0%
Jun	8,640	233	2.7%	93	1.1%	0	0.0%
Jul	8,928	314	3.5%	135	1.5%	3	0.0%
Aug	8,928	219	2.5%	85	1.0%	0	0.0%
Sep	8,640	292	3.4%	133	1.5%	4	0.0%
Total	78,612	2,307	2.9%	1,045	1.3%	27	0.0%

80 A case is executed when it begins to solve. Most but not all cases are solved. SCED cases take about one to two minutes to solve.

While a single solved SCED case indicating a shortage for a target interval among multiple SCED cases that solved for that interval could be the result of operator bias or erroneous inputs, it is less likely that an interval with multiple RT SCED cases indicating shortage was the result of an error. There were 27 five minute intervals with shortage pricing that occurred on fourteen days in the first nine months of 2019, while there were 1,045 five minute intervals where multiple solved SCED cases showed a shortage of reserves. The data indicates reluctance on the part of PJM operators to approve SCED cases with a shortage.

The PJM Real-Time Energy Market produces an efficient outcome only when prices are allowed to reflect the fundamental supply and demand conditions in the market in real time. While it is appropriate for operators to ensure that cases use data that reflect the actual state of the system, it is essential that operator discretion not extend beyond what is necessary and that operator discretion not prevent shortage pricing when there are shortage conditions. This is a critical issue now that PJM settles all real-time energy transactions on a five minute basis using the prices calculated by LPC. The MMU recommends that PJM clearly define the criteria for operator approval of RT SCED cases used to send dispatch signals to resources, and for pricing, to minimize operator discretion and implement a rule based approach.

Shortage Pricing Intervals in LPC

There were 27 intervals with five minute shortage pricing that occurred on 14 days in the first nine months of 2019, compared to zero intervals in the first nine months of 2018, in PJM. In 26 of the 27 intervals, shortage pricing was triggered only due to synchronized reserves being short of the extended synchronized reserve requirement.[81] In one of the 27 intervals, shortage pricing was triggered due to both synchronized reserves and primary reserves being short of their extended reserve requirements. Table 3-68 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the RTO reserve zone during the 27 intervals with shortage pricing due to synchronized reserve shortage. Table 3-69 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the MAD reserve subzone during the 27 intervals with shortage pricing due to synchronized reserve shortage. Table 3-70 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the RTO reserve zone during the one interval with shortage pricing due to primary reserve shortage. Table 3-71 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the MAD reserve subzone during the one interval with shortage pricing due to primary reserve shortage.

PJM enforces an RTO wide reserve requirement and a supplemental reserve requirement for the MAD region. The MAD reserve subzone is nested within the RTO reserve zone. Resources located in the MAD reserve subzone can simultaneously satisfy the synchronized reserve requirement of the RTO reserve zone and the synchronized reserve requirement of the MAD reserve subzone. Resources located outside the MAD reserve subzone can satisfy the synchronized reserve requirement of the RTO reserve zone, and subject to transfer limits defined by transmission constraints, satisfy the reserve requirement of the MAD Subzone. The synchronized reserve clearing price of the RTO reserve zone is set by the shadow price of the binding reserve requirement constraint of the RTO reserve zone.[82] The synchronized reserve clearing price of the MAD reserve subzone, nested within the RTO reserve zone, is set by the sum of the shadow prices of the binding reserve requirement constraint of the RTO reserve zone and the shadow price of the binding reserve requirement constraint of the MAD reserve subzone.

In all 27 intervals in the first nine months of 2019 with shortage pricing, both the RTO Zone and the MAD Subzone cleared with synchronized reserves less than their extended requirement. The clearing price for synchronized reserves in the RTO Zone is the sum of the shadow prices of the synchronized reserve constraint for the RTO Zone and the primary reserve constraint for the RTO Zone. The clearing price for synchronized reserves in the MAD Subzone is

81 The extended synchronized reserve requirement is defined as the reliability synchronized reserve requirement plus 190 MW.

82 If the reserve requirement cannot be met by the resources located within the reserve zone, the shadow price of the reserve requirement is set the applicable operating reserve demand curve.

the sum of the shadow prices of the synchronized reserve constraints for the RTO Zone and MAD Subzone and the shadow prices of the primary reserve constraints in the RTO and MAD Subzone. For the two intervals on March 18 at 0635 EPT and March 19 at 0535 EPT, the clearing prices for RTO and MAD synchronized reserves reflect the non-zero shadow price of the RTO primary reserve constraint in addition to the synchronized reserve constraint shadow prices. On January 31, March 12, and April 1, 2019, the RTO synchronized reserve price exceeded $300 per MWh because the synchronized reserve shortage MW equals 190 MW, the second step of the synchronized reserve demand curve. On April 8, 2019, the RTO synchronized reserve price exceeded $300 per MWh because the synchronized reserve shortage MW is greater than 190 MW, the second step of the synchronized reserve demand curve.

Table 3-68 RTO Synchronized Reserve Shortage Intervals: January through September, 2019

Interval (EPT)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	RTO Synchronized Reserve Clearing Price ($/MWh)
09-Jan-19 16:35	1,678.0	1,548.9	129.1	$300.0
30-Jan-19 18:00	1,681.0	1,538.6	142.4	$300.0
31-Jan-19 01:30	1,856.0	1,666.0	190.0	$620.5
06-Mar-19 22:10	1,645.5	1,562.2	83.3	$300.0
06-Mar-19 22:15	1,645.4	1,515.3	130.1	$300.0
12-Mar-19 07:20	1,615.7	1,610.2	5.5	$300.0
12-Mar-19 07:25	1,615.5	1,425.5	190.0	$457.9
12-Mar-19 07:30	1,615.3	1,425.3	190.0	$412.5
16-Mar-19 07:05	1,834.0	1,676.5	157.5	$300.0
16-Mar-19 07:10	1,841.0	1,814.2	26.8	$300.0
17-Mar-19 19:55	1,818.0	1,641.7	176.3	$300.0
18-Mar-19 06:35	1,860.0	1,810.2	49.8	$309.0
19-Mar-19 05:35	1,854.0	1,789.4	64.6	$421.3
01-Apr-19 19:50	1,841.0	1,651.0	190.0	$692.8
01-Apr-19 19:55	1,846.0	1,706.8	139.2	$300.0
01-Apr-19 20:00	1,847.0	1,657.0	190.0	$663.0
08-Apr-19 06:55	1,535.9	1,423.4	112.5	$300.0
08-Apr-19 07:00	1,538.1	1,178.6	359.5	$850.0
08-Apr-19 07:05	1,538.1	1,178.6	359.5	$850.0
08-Apr-19 07:10	1,538.9	1,430.8	108.1	$300.0
01-Jul-19 16:55	1,817.1	1,813.8	3.3	$300.0
01-Jul-19 17:00	1,817.5	1,500.8	316.7	$1,472.3
01-Jul-19 17:05	1,817.7	1,700.6	117.1	$307.3
03-Sep-19 16:55	1,795.3	1,593.9	201.4	$1,150.0
03-Sep-19 17:00	1,795.3	1,593.9	201.4	$1,150.0
07-Sep-19 15:20	1,990.0	1,800.0	190.0	$847.5
07-Sep-19 15:25	1,990.0	1,800.0	190.0	$847.5

Table 3-69 MAD Synchronized Reserve Shortage Intervals: January through September, 2019

Interval (EPT)	MAD Extended Synchronized Reserve Requirement (MW)	Total MAD Synchronized Reserves (MW)	MAD Synchronized Reserve Shortage (MW)	MAD Synchronized Reserve Clearing Price ($/MWh)
09-Jan-19 16:35	1,678.0	1,548.9	129.1	$600.0
30-Jan-19 18:00	1,681.0	1,538.6	142.4	$600.0
31-Jan-19 01:30	1,856.0	1,666.0	190.0	$920.5
06-Mar-19 22:10	1,645.5	1,562.2	83.3	$600.0
06-Mar-19 22:15	1,645.4	1,515.3	130.1	$600.0
12-Mar-19 07:20	1,615.7	1,610.2	5.5	$600.0
12-Mar-19 07:25	1,615.5	1,425.5	190.0	$757.9
12-Mar-19 07:30	1,615.3	1,425.3	190.0	$712.5
16-Mar-19 07:05	1,834.0	1,676.5	157.5	$600.0
16-Mar-19 07:10	1,841.0	1,814.2	26.8	$600.0
17-Mar-19 19:55	1,818.0	1,641.7	176.3	$600.0
18-Mar-19 06:35	1,860.0	1,810.2	49.8	$609.0
19-Mar-19 05:35	1,854.0	1,789.4	64.6	$721.3
01-Apr-19 19:50	1,841.0	1,651.0	190.0	$992.8
01-Apr-19 19:55	1,846.0	1,706.8	139.2	$600.0
01-Apr-19 20:00	1,847.0	1,657.0	190.0	$963.0
08-Apr-19 06:55	1,535.9	1,423.4	112.5	$600.0
08-Apr-19 07:00	1,538.1	1,178.6	359.5	$1,700.0
08-Apr-19 07:05	1,538.1	1,178.6	359.5	$1,700.0
08-Apr-19 07:10	1,538.9	1,430.8	108.1	$600.0
01-Jul-19 16:55	1,817.1	1,813.8	3.3	$600.0
01-Jul-19 17:00	1,817.5	1,500.8	316.7	$1,700.0
01-Jul-19 17:05	1,817.7	1,700.6	117.1	$607.3
03-Sep-19 16:55	1,795.3	1,593.9	201.4	$1,700.0
03-Sep-19 17:00	1,795.3	1,593.9	201.4	$1,700.0
07-Sep-19 15:20	1,990.0	1,800.0	190.0	$1,147.5
07-Sep-19 15:25	1,990.0	1,800.0	190.0	$1,147.5

Table 3-70 RTO Primary Reserve Shortage Intervals: January through September, 2019

Interval (EPT)	RTO Extended Primary Reserve Requirement (MW)	Total RTO Primary Reserves (MW)	RTO Primary Reserve Shortage (MW)	RTO Primary Reserve Clearing Price ($/MWh)
01-Jul-19 17:00	2,631.3	2,468.0	163.2	$300.0

Table 3-71 MAD Primary Reserve Shortage Intervals: January through September, 2019

Interval (EPT)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	MAD Primary Reserve Clearing Price ($/MWh)
01-Jul-19 17:00	2,631.3	2,468.0	163.2	$600.0

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, such as tier 1 bias or operator load bias. 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.[83] PJM cannot accurately measure or price reserves due to the inaccuracy of its generator models. PJM's commitment and dispatch models rely on generator data to properly commit and dispatch generators. Generator data includes offers and parameters. When the models do not properly account for the different generator characteristics, both PJM dispatchers and generators have to make simplifications and assumptions using the tools available. Most of these

83 See Comments of the Independent Market Monitor for PJM, Docket No. RM15-24-000 (December 1, 2015) at 9.

actions taken by generators and by PJM dispatchers are not transparent. PJM manuals do not provide clarity regarding what actions generators can take when the PJM models and tools do not reflect their operational characteristics and PJM manuals do not provide sufficient clarity regarding the actions PJM dispatchers can take when generators do not follow dispatch.

In the energy and reserve markets, the actions that both generators and PJM dispatchers take have a direct impact on the amount of supply available for energy and reserves and the prices for energy and reserves. These flaws in PJM's models do not allow PJM to accurately calculate the amount of reserves available. PJM does not accurately model discontinuities in generator ramp rates, such as duct burners on combined cycle plants. PJM's generator models do not account for the complexities that may result in generators underperforming their submitted ramp rates. Instead of addressing these complexities through generator modeling improvements, PJM relies on a nontransparent method of adjusting generator parameters, called Degree of Generator Performance (DGP).[84] PJM also fails to accurately model unit starts. The market software does not account for the energy output a resource produces prior to reaching its economic minimum output level, during its soak time.

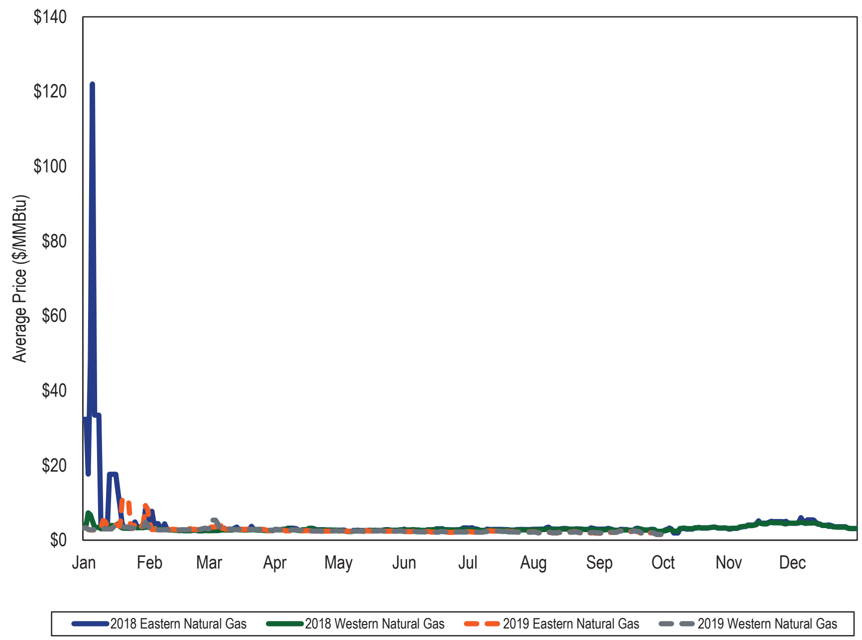
PJM adjusts ramp rates using the DGP metric, deselects specific units from providing reserves, and overrides the dispatch signal to certain units to set it equal to actual resource output. These manual interventions are crude approximations of the capability of generators and result in an inaccurate measurement of reserves.

PJM Cold Weather Operations 2019

Natural Gas Supply and Prices

As of September 30, 2019, gas fired generation was 42.1 percent (78,477.3 MW) of the total installed PJM capacity (186,502.9 MW).[85] Figure 3-49 shows the average daily price of delivered natural gas for eastern and western parts of PJM service territory in 2018 and the first nine months of 2019.[86]

Figure 3-49 Average daily delivered price for natural gas: 2018 and 2019 ($/MMBtu)



During the first nine months of 2019, 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. These notices 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

84 *See* PJM Manual 12 (Revision 39, Effective February 21, 2019) Attachment A, P78. PJM Manual 11 (Energy and Ancillary Services Market Operations) does not mention the use of DGP in the market clearing engine.
85 *2019 Quarterly State of the Market Report for PJM: January through September*, Section 5: Capacity Market, at Installed Capacity.
86 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.

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.

Competitive Assessment

Market Structure

Market Concentration

Analysis of supply curve segments of the PJM energy market in the first nine months of 2019 indicates low concentration in the base load segment, and high concentration in the intermediate segment and the peaking segment.[87] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal in the aggregate market. 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.

87 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.

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 2019, 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 with scheduled imports (Table 3-72).

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:[88]

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

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. This is called the Lerner Index. 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 customers. The Lerner Index is a measure of market power that

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

connects market structure (HHI and demand elasticity) to market performance (markup).

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 indicate issues with the ownership of incremental resources. An aggregate pivotal supplier test is required to accurately measure the ability of incremental resources to exercise market power when load is high, for example.

Hourly HHIs were also calculated for baseload, intermediate and peaking segments of generation supply. Hourly energy market HHIs by supply curve segment were calculated based on hourly energy market shares, unadjusted for imports.

The "Merger Policy Statement" of FERC states that a market can be broadly characterized as:

- **Unconcentrated.** Market HHI below 1000, equivalent to 10 firms with equal market shares;
- **Moderately Concentrated.** Market HHI between 1000 and 1800; and
- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[89]

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 electricity demand elasticity ranging from -0.2 to -0.4.[90] Using the Lerner Index, the elasticities imply, for example, an average markup ranging from 25 to 50 percent at the unconcentrated to moderately concentrated threshold HHI of 1000:[91]

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

With knowledge of HHI, elasticity, and marginal cost, one can solve for the price level theoretically indicated by the Lerner Index, based on profit maximizing behavior including the exercise of market power. With marginal costs of $25.65 per MWh and an average HHI of 773 in the first nine months of 2019, average PJM prices would theoretically range from $32 to $42 per MWh using the elasticity range of -0.2 to -0.4.[92] The theoretical prices exceed marginal costs because the exercise of market power is profit maximizing in the absence of market power mitigation. Actual prices, averaging $27.60 per MWh, and markups, at 7.1 percent, 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 2019 was unconcentrated (Table 3-72).

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

90 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>.

91 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.

92 The average HHI is found in Table 3-72. Marginal costs are the sum of all components of LMP except markup, as shown in Table 3-57.

Table 3-72 Hourly energy market HHI: January through September, 2018 and 2019[93]

	Hourly Market HHI (Jan - Sep, 2018)	Hourly Market HHI (Jan - Sep, 2019)
Average	821	773
Minimum	609	572
Maximum	1165	1098
Highest market share (One hour)	28%	26%
Average of the highest hourly market share	19%	19%
# Hours	6,551	6,551
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-73 includes HHI values by supply curve segment, including base, intermediate and peaking plants for the first nine months of 2018 and 2019. The PJM energy market was unconcentrated overall with low concentration in the baseload segment and high concentration in the intermediate segment and the peaking segment.

Table 3-73 Hourly energy market HHI (By supply segment): January through September, 2018 and 2019

	Jan - Sep, 2018			Jan - Sep, 2019		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	725	892	1283	659	808	1120
Intermediate	733	1483	5030	694	1803	9237
Peak	679	6071	10000	701	6241	10000

93 This analysis includes all hours in the first nine months of 2018 and 2019, regardless of congestion.

Figure 3-50 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 2019.

Figure 3-50 Fuel source distribution in unit segments: January through September, 2019[94]

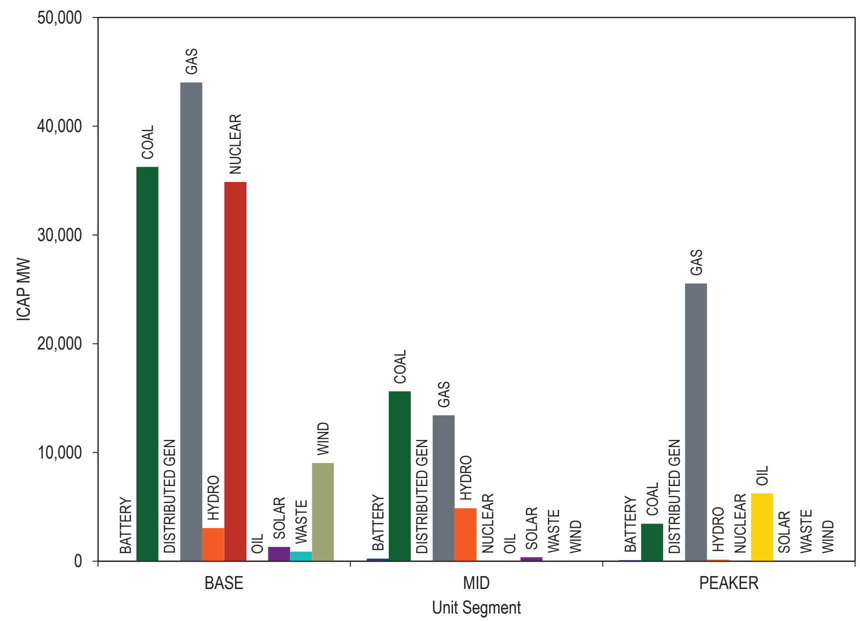


Figure 3-51 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking segments for the first nine months from 2015 through 2019. Figure 3-51 shows that the total ICAP of coal fired units in PJM that are classified as baseload has been steadily decreasing and the total ICAP of gas fired units in PJM that are classified as baseload is steadily increasing using operating history for the period from

94 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>.

2015 through 2019. In the first nine months of 2019, ICAP of gas fired units classified as baseload exceeded ICAP of coal fired units classified as baseload for the first time.

Figure 3-51 Unit segment classification by fuel: January through September, 2015 through 2019

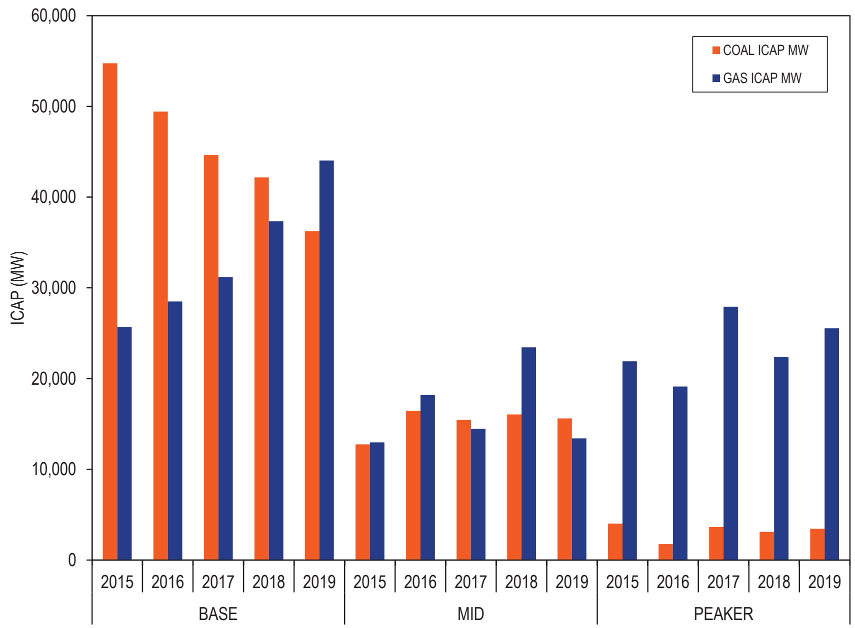
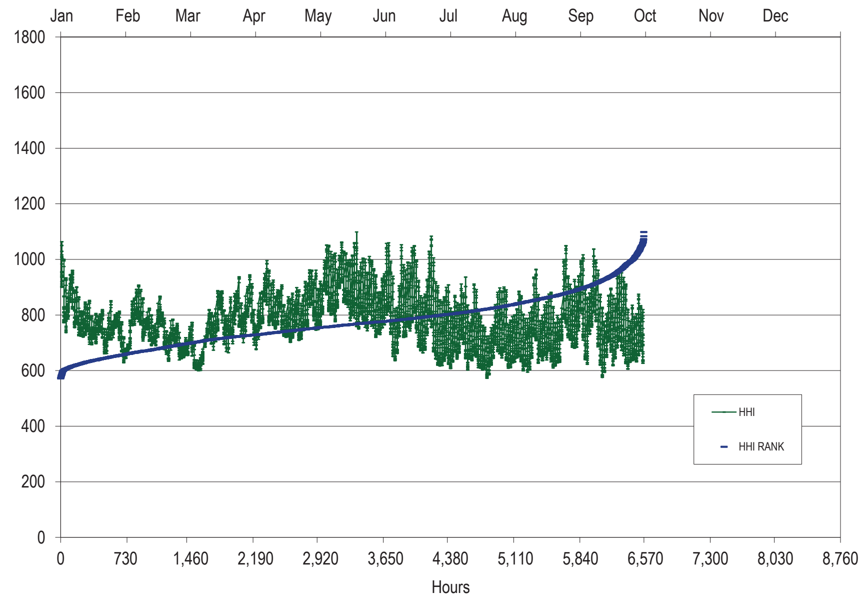


Figure 3-52 presents the hourly HHI values in chronological order and an HHI duration curve for the first nine months of 2019.

Figure 3-52 Hourly energy market HHI: January through September, 2019



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."[95]

FERC applies tests set forth in the 1996 Merger Policy Statement.[96] FERC currently is reviewing those guidelines.[97]

95 18 U.S.C. § 824b.
96 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).
97 See 156 FERC ¶ 61,214 (2016); FERC Docket No. RM16-21-000.

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, 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. 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.[98] The MMU has proposed that FERC adopt this approach when evaluating mergers in PJM.[99] FERC has considered the MMU's analysis in reviewing mergers.[100]

The MMU has also facilitated settlements for mitigation of market power, in cases where market power concerns have been identified.[101] 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." In February 2019, the Commission issued Order No. 855 amending Section 203 of the Federal Power Act to implement the $10,000,000 minimum value for transactions requiring the Commission's review.[102]

98 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)

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

100 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).

101 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, one supplier was singly pivotal on the summer peak day, two suppliers were jointly pivotal on 28 days, and three suppliers were jointly pivotal on 164 days in the first nine months of 2019. The frequency of pivotal suppliers increased during the summer months of 2018 and 2019, on high demand days in September 2018 and 2019, from January 1 to 10, 2018, and on January 22, 2019. On January 22, 2019, total energy market uplift and energy offer markups exceeded average levels for the quarter.

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.

102 See 166 FERC ¶ 61,120 (2019), Docket No. RM19-4.

The existing market power mitigation measures do not address aggregate market power.[103] 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.[104] 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 3-53 shows the number of days in 2018 and in the first nine months of 2019 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 2018, and one supplier was singly pivotal on the summer peak day in 2019. Two suppliers were jointly pivotal on 42 days in 2018 and on 28 days in the first nine months of 2019. Three suppliers were jointly pivotal on 212 days in 2018 and 164 days in the first nine months of 2019, despite average HHIs at persistently unconcentrated levels. In 2018 and 2019, the highest levels of aggregate market power occur in the third quarter, PJM's peak load season. In the first nine months of 2019, the highest levels of aggregate market power occurred on July 2 and July 16 through 21, 2019.

Figure 3-53 Days with pivotal suppliers and numbers of pivotal suppliers in the Day-Ahead Energy Market by quarter

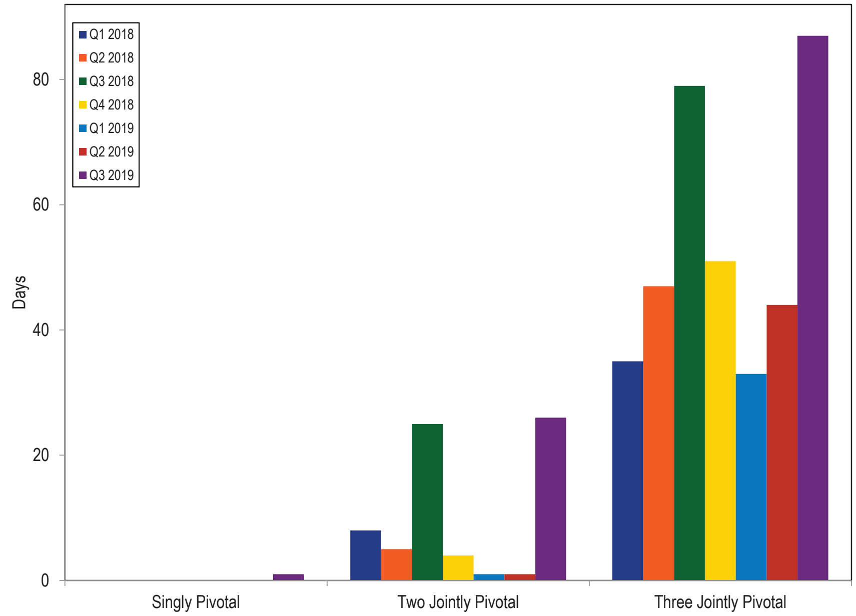


Table 3-74 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the Day-Ahead Energy Market in 2019. The first pivotal supplier was pivotal on July 19, 2019. The first and second pivotal suppliers were pivotal on 9.9 percent of days in the first nine months of 2019. All of the top 10 suppliers were one of three pivotal suppliers on at least 61 days in the first nine months of 2019.

103 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).

104 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.

Table 3-74 Day-ahead market pivotal supplier frequency: January through September, 2019

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	1	0.4%	27	9.9%	167	61.2%
2	0	0.0%	27	9.9%	164	60.1%
3	0	0.0%	20	7.3%	167	61.2%
4	0	0.0%	8	2.9%	132	48.4%
5	0	0.0%	8	2.9%	131	48.0%
6	0	0.0%	3	1.1%	67	24.5%
7	0	0.0%	1	0.4%	85	31.1%
8	0	0.0%	1	0.4%	73	26.7%
9	0	0.0%	1	0.4%	68	24.9%
10	0	0.0%	1	0.4%	61	22.3%

Market Behavior

Local Market Power

In the PJM energy market, market power mitigation rules currently apply only for local market power. Local market power exists when transmission constraints or reliability issues create local markets that are structurally noncompetitive. If the owners of the units required to solve the constraint or reliability issue are pivotal or jointly pivotal, they have the ability to set the price. Absent market power mitigation, unit owners that submit noncompetitive offers, or offers with inflexible operating parameters, could exercise market power. This could result in LMPs being set at higher than competitive levels, or could result in noncompetitive uplift payments.

The three pivotal supplier (TPS) test is the test for local market power in the energy market.[105] If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners who have been identified as having local market power. Offer capping is designed to set offers at competitive levels. Competitive offers are defined to be cost-based energy offers. In the PJM energy market, units are required to submit cost-based energy offers, defined by fuel cost policies, and have the option to submit market-based or price-based offers. Units are committed and dispatched on price-based offers, if offered, as the default offer. When a unit that submits both cost-based and price-based offers is mitigated to its cost-based offer by PJM, it is considered offer capped. A unit that submits only cost-based offers, or that requests PJM to dispatch it on its cost-based offer, is not considered offer capped.

Local market power mitigation is implemented in both the Day-Ahead and Real-Time Energy Markets. However, the implementation of the TPS test and offer capping differ in the Day-Ahead and Real-Time Energy Markets.

Day-Ahead Local Market Power Mitigation

In the Day-Ahead Energy Market, the TPS test is performed in a tool that is separate from the Day-Ahead market clearing software, called PROBE. PROBE is third party software, and the details of how it dispatches the system, estimates binding constraints, and calculates TPS and offer capping results are proprietary information not available to PJM or the MMU. PROBE uses the results from PJM's Resource Scheduling and Commitment (RSC) tool as an input to generate its day-ahead market solution and TPS test results. PROBE includes both physical and virtual bids and offers, including generation, physical load, virtual supply (INCs), virtual demand (DECs) and up to congestion (UTC) transactions to clear the market. Transmission constraints in the Day-Ahead Energy Market can be caused by the flow of energy that results from all these transactions. PROBE uses only physical resources and virtual supply (increment offers) as sources of relief to binding transmission constraints. If a unit owner fails the TPS test for a constraint, PROBE picks the unit schedule resulting in the lowest bid production cost for the system over the 24 hour commitment period. This calculation is internal to the PROBE software, so the MMU does not have access to the information necessary to evaluate its assumptions or accuracy.

A unit that is offer capped in PROBE does not necessarily result in the unit being offer capped in the final day-ahead market results. The process used to determine the final set of units subject to offer capping in the day-ahead market is not transparent and is not documented in the PJM manuals.

Real-Time Local Market Power Mitigation

In the Real-Time Energy Market, the TPS test is embedded in the IT SCED tool, which is a look ahead commitment and dispatch tool. In the Real-Time Energy Market, the TPS test uses physical resources, physical load forecasts, and reserve requirements to commit resources available in a look ahead window. The IT SCED tool is executed every five minutes and solves for four future intervals: a minimum of 135 minutes; 90 minutes; 45 minutes; and 30 minutes ahead. The TPS test results in offer capping recommendations applicable to online and offline resources.

PJM dispatchers use the recommendations from the IT SCED tool to commit resources to provide relief to a constraint on the cheaper of the price or cost schedule at the time of commitment, using the dispatch cost formula. Since each IT SCED case solution produces TPS test results for four look ahead intervals for each individual constraint that requires relief, it is unclear how dispatchers use all the available TPS results to select a unit to commit and the schedule to commit the unit on.

Another limitation of running the TPS test in IT SCED is that market conditions may differ between the IT SCED solution and the RT SCED solution that is used to dispatch and price the system. Constraints may create local market power differently in the RT SCED model than in the IT SCED model. Market power in the RT SCED may go unmitigated.

TPS Test Statistics for Local Market Power

The TPS test in the energy market defines whether one, two or three suppliers are jointly pivotal in a defined local market. The TPS test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. The TPS test result for a constraint for a specific interval indicates whether a supplier failed or passed the test for that constraint for that interval. A failed test indicates that the resource owner has structural market power.

A metric to describe the number of local markets created by transmission constraints and the applicability of the TPS is the number of hours that each transmission constraint was binding in the real-time energy market over a period, by zone.

In the first nine months of 2019, the AECO, AEP, ATSI, BGE, ComEd, Dominion, Met-Ed, PECO, PENELEC, PPL 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 3-75). The APS, DAY, DEOK, DLCO, DPL, EKPC, JCPL, OVEC, Pepco, and RECO control zones did not have constraints binding for 75 or more hours in the first nine months of 2019. Table 3-75 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 2019.

Table 3-75 Congestion hours resulting from one or more constraints binding for 75 or more hours or from an interface constraint: January through September, 2009 through 2019

	(Jan - Sep)										
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
AECO	149	163	234	0	0	0	192	413	0	94	97
AEP	1,005	1,265	2,452	178	2,018	1,821	1,891	633	469	1,592	595
APS	421	1,121	87	89	0	170	451	157	136	184	0
ATSI	140	0	0	208	68	481	424	1	427	2,355	259
BGE	127	274	368	1,582	1,192	4,416	6,006	8,506	1,748	2,644	622
ComEd	784	2,108	1,118	1,808	3,169	1,928	1,708	4,754	1,401	761	78
DEOK	0	0	0	185	0	0	0	0	0	75	0
DLCO	156	393	0	209	0	223	617	0	0	0	0
Dominion	456	889	1,266	559	674	77	1,341	647	80	136	90
DPL	0	111	0	382	783	542	1,138	2,691	326	398	0
EKPC	0	0	0	0	0	0	0	0	0	368	0
JCPL	0	0	0	0	0	0	79	0	94	0	0
Met-Ed	0	168	0	0	0	0	222	0	0	1,259	548
PECO	247	0	276	0	390	1,826	718	826	975	218	83
PENELEC	80	96	77	0	0	2,147	1,287	451	1,992	1,338	1,006
Pepco	149	0	76	143	200	41	0	0	0	0	0
PPL	176	117	40	146	609	148	224	398	1,370	0	718
PSEG	379	515	1,132	259	1,993	2,268	2,509	170	159	324	174

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 2019.[106] While the real-time constraint hours include constraints that were binding in the five minute real-time pricing solution (LPC), IT SCED may contain different binding constraints because IT SCED looks ahead to intervals that are in the near future to solve for constraints that could be binding, using the load forecast for these intervals. The TPS statistics shown in this section present the data from the IT SCED TPS solution. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Table 3-76 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 3-77 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 ten constraints that were binding for the most hours in the PJM Real-Time Energy Market. Table 3-76 and Table 3-77 include analysis of all the tests for every interval where IT SCED determined that constraint relief was needed for each of the constraints shown. The same interval can be evaluated by multiple IT SCED cases at different look ahead times.

Table 3-76 Three pivotal supplier test details for interface constraints: January through September, 2019

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AP South	Peak	611	708	12	1	11
	Off Peak	464	575	13	2	11
Eastern	Peak	897	960	16	1	15
	Off Peak	648	756	14	0	13
PA Central	Peak	49	160	4	0	4
	Off Peak	71	192	4	0	4
Cleveland	Peak	NA	NA	NA	NA	NA
	Off Peak	392	369	27	0	27

Table 3-77 Three pivotal supplier test details for top 10 congested constraints: January through September, 2019

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Conastone - Peach Bottom	Peak	284	503	20	10	10
	Off Peak	258	466	18	9	9
Graceton - Safe Harbor	Peak	88	118	11	3	8
	Off Peak	64	91	10	3	8
Lenox - North Meshoppen	Peak	22	55	2	0	2
	Off Peak	7	48	1	0	1
East Towanda - Hillside	Peak	28	141	2	0	2
	Off Peak	25	166	1	0	1
Asylum - East Towanda	Peak	16	257	1	0	1
	Off Peak	8	237	1	0	1
Siegfried	Peak	44	51	3	0	3
	Off Peak	43	58	3	0	3
Face Rock	Peak	23	14	1	0	1
	Off Peak	13	5	1	0	1
Tanners Creek - Miami Fort	Peak	142	172	5	0	5
	Off Peak	148	185	5	0	5
Boonetown - South Reading	Peak	37	124	2	0	2
	Off Peak	33	70	3	0	3
Haviland	Peak	20	32	1	0	1
	Off Peak	23	19	1	0	1

106 See the MMU Technical Reference for PJM Markets, p. 38 "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

The three pivotal supplier test is applied every time the IT SCED 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 offer 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 3-78 and Table 3-79 provide, for the identified 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 providing relief to a binding constraint.

Table 3-78 Summary of three pivotal supplier tests applied for interface constraints: January through September, 2019

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
AP South	Peak	337	333	99%	7	2%	2%
	Off Peak	148	148	100%	2	1%	1%
Eastern	Peak	242	242	100%	24	10%	10%
	Off Peak	120	120	100%	2	2%	2%
PA Central	Peak	1,379	1,053	76%	0	0%	0%
	Off Peak	93	43	46%	0	0%	0%
Cleveland	Peak	0	0	NA	0	NA	NA
	Off Peak	4	4	100%	0	0%	0%

Table 3-79 Summary of three pivotal supplier tests applied for top 10 congested constraints: January through September, 2019

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
Conastone - Peach Bottom	Peak	47,736	47,724	100%	2,193	5%	5%
	Off Peak	35,640	35,631	100%	983	3%	3%
Graceton - Safe Harbor	Peak	3,190	3,112	98%	7	0%	0%
	Off Peak	9,470	9,431	100%	43	0%	0%
Lenox - North Meshoppen	Peak	5,145	2,450	48%	4	0%	0%
	Off Peak	4,238	948	22%	0	0%	0%
East Towanda - Hillside	Peak	3,586	2,012	56%	0	0%	0%
	Off Peak	2,668	810	30%	0	0%	0%
Asylum - East Towanda	Peak	1,902	204	11%	0	0%	0%
	Off Peak	1,296	101	8%	0	0%	0%
Siegfried	Peak	7,544	3,277	43%	1	0%	0%
	Off Peak	6,692	2,878	43%	1	0%	0%
Face Rock	Peak	299	114	38%	0	0%	0%
	Off Peak	70	57	81%	0	0%	0%
Tanners Creek - Miami Fort	Peak	5,177	4,870	94%	232	4%	5%
	Off Peak	2,351	2,173	92%	57	2%	3%
Boonetown - South Reading	Peak	2,107	1,045	50%	4	0%	0%
	Off Peak	716	395	55%	0	0%	0%
Haviland	Peak	1,656	338	20%	2	0%	1%
	Off Peak	2,042	31	2%	0	0%	0%

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.

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-based 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.[107] 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:

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

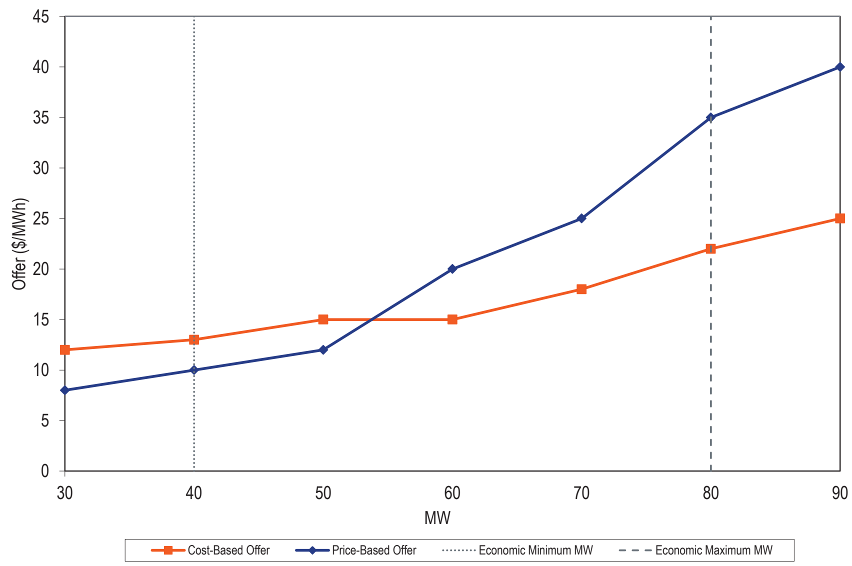
where the hourly dispatch cost is calculated for each hour using the offers applicable for that hour as:

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

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 evade mitigation by using a low markup at low output levels and a high markup at higher output levels. Figure 3-54 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.

107 See PJM Operating Agreement Schedule 1 § 6.4.1(g).

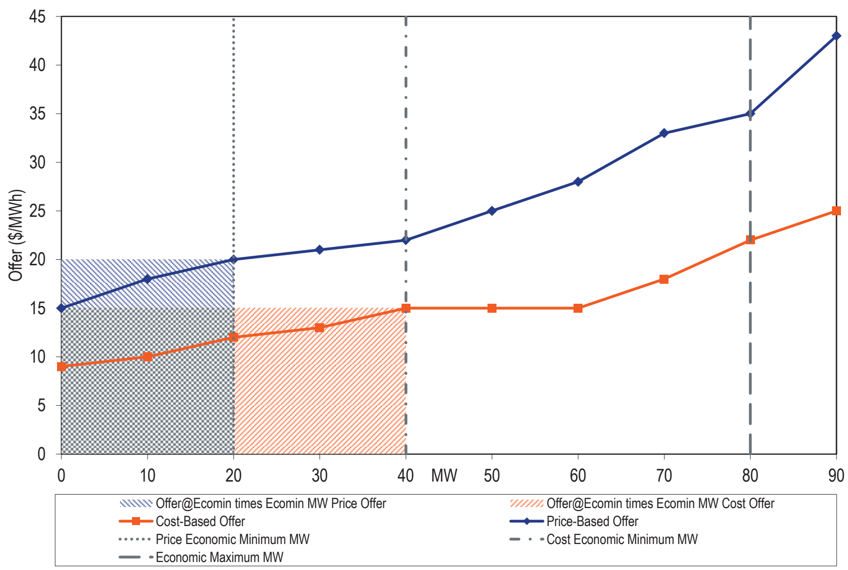
Figure 3-54 Offers with varying markups at different MW output levels



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.

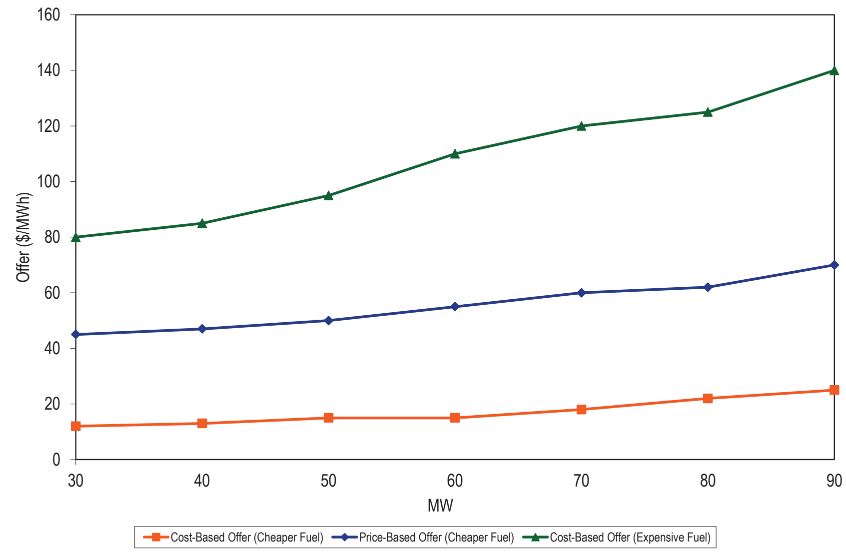
A unit may offer a lower economic minimum MW level on the price-based offer than the cost-based offer. Such a unit may appear to be cheaper to commit on the price-based offer even with a positive markup. A unit with a positive markup can have lower dispatch cost with the price-based offer with a lower economic minimum level compared to cost-based offer. Figure 3-55 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 3-55 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 3-56 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 3-56 Dual fuel unit offers



These issues can be solved by simple rule changes.[108] 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 3-81. 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. Until November 1, 2017, only uncommitted resources, started to relieve the transmission constraint, were subject to offer capping. Beginning November 1, 2017, under certain circumstances, online resources that are committed

108 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.

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 lower than the price-based offer.[109] Units running in real time as part of their original commitment on the price-based offer on economics, and that can provide incremental relief to a constraint, cannot be switched to their cost-based offer.

The offer capping percentages shown in Table 3-80 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.[110] 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 2018 and 2019 compared to 2017.

Table 3-80 Offer capping statistics – energy only: January through September, 2015 to 2019

	Real-Time		Day-Ahead	
(Jan-Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
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%
2019	1.6%	1.1%	1.1%	0.7%

Table 3-81 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 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 3-80.

Table 3-81 Offer capping statistics for energy and reliability: January through September, 2015 to 2019

	Real-Time		Day-Ahead	
(Jan-Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
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%
2019	1.6%	1.1%	1.1%	0.7%

Table 3-82 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 3-82 is the difference between the offer cap percentages shown in Table 3-81 and Table 3-80.

Table 3-82 Offer capping statistics for reliability: January through September, 2015 to 2019

	Real-Time		Day-Ahead	
(Jan-Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
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%
2019	0.0%	0.0%	0.0%	0.0%

109 See OATT Attachment K Appendix § 6.4.1.
110 Prior to the 2018 Quarterly State of the Market report for PJM: January through June, these tables presented the offer cap percentages based on total bid unit hours and total load MWh. Beginning with the quarterly report for January through June, 2018, the statistics have been updated with percentages based on run hours and total generation MWh from units modeled in the energy market.

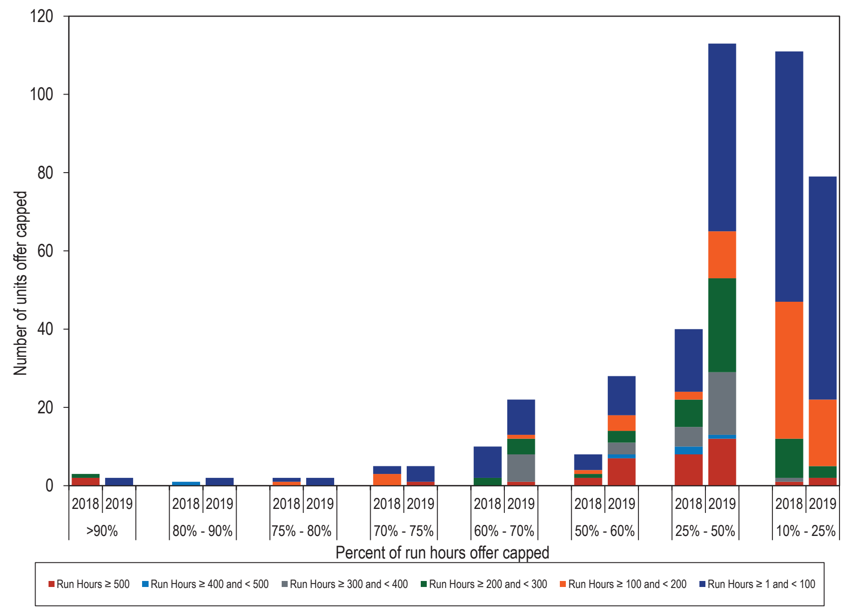
Table 3-83 presents data on the frequency with which units were offer capped in the first nine months of 2018 and 2019 as a result of failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market and for reliability reasons. Table 3-83 shows that two units were offer capped for 90 percent or more of their run hours in the first nine months of 2019 compared to three units in the first nine months of 2018.

Table 3-83 Real-time offer capped unit statistics: January through September, 2018 and 2019

		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
	2018	2	0	0	1	0	0
90%	2019	0	0	0	0	0	2
	2018	0	1	0	0	0	0
80% and < 90%	2019	0	0	0	0	0	2
	2018	0	0	0	0	1	1
75% and < 80%	2019	0	0	0	0	0	2
	2018	0	0	0	0	3	2
70% and < 75%	2019	1	0	0	0	0	4
	2018	0	0	0	2	0	8
60% and < 70%	2019	1	0	7	4	1	9
	2018	2	0	0	1	1	4
50% and < 60%	2019	7	1	3	3	4	10
	2018	8	2	5	7	2	16
25% and < 50%	2019	12	1	16	24	12	48
	2018	1	0	1	10	35	64
10% and < 25%	2019	2	0	0	3	17	57

Figure 3-57 shows the frequency with which units were offer capped in the first nine months of 2018 and 2019 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market and for reliability reasons.

Figure 3-57 Real-time offer capped unit statistics: January through September, 2018 and 2019



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.[111] 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

111 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.

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 3-84 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using unadjusted cost-based offers. Table 3-85 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.[112] 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.

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 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.[113]

In the first nine months of 2019, 97.6 percent of marginal units had offer prices less than $50 per MWh. The average dollar markups of units with offer prices less than $25 was positive ($0.18 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $25 and $50 was positive ($1.77 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 month of 2019, less than 0.1 percent had offer prices above $400 per MWh. Among the units that were marginal in the first nine months of 2018, 0.1 percent 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 2019 was more than $400, while the highest markup in the first nine months of 2018 was more than $500.

Table 3-84 Average, real-time marginal unit markup index (By offer price category unadjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)			2019 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.03	($0.46)	55.2%	0.03	$0.18	77.5%
$25 to $50	0.07	$2.24	34.6%	0.07	$1.77	20.2%
$50 to $75	0.35	$19.93	3.2%	0.37	$22.17	1.0%
$75 to $100	0.33	$27.13	1.1%	0.57	$48.74	0.4%
$100 to $125	0.31	$33.99	0.6%	0.34	$36.36	0.3%
$125 to $150	0.11	$15.28	1.2%	0.48	$66.73	0.1%
$150 to $400	0.07	$14.41	4.0%	0.07	$14.78	0.5%
>= $400	0.49	$241.08	0.1%	0.11	$51.44	0.0%

112 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.

113 See PJM. "Manual 15: Cost Development Guidelines," Rev. 32 (May 13, 2019).

Table 3-85 Average, real-time marginal unit markup index (By offer price category adjusted): January through September 2018 and 2019

	2018 (Jan - Sep)			2019 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.11	$1.22	55.2%	0.11	$1.82	77.5%
$25 to $50	0.15	$4.91	34.6%	0.15	$4.33	20.2%
$50 to $75	0.41	$23.27	3.2%	0.43	$25.41	1.0%
$75 to $100	0.39	$32.34	1.1%	0.61	$52.05	0.4%
$100 to $125	0.38	$40.98	0.6%	0.40	$42.86	0.3%
$125 to $150	0.20	$26.18	1.2%	0.53	$73.12	0.1%
$150 to $400	0.16	$32.28	4.0%	0.16	$30.19	0.5%
>= $400	0.53	$261.61	0.1%	0.20	$87.44	0.0%

Table 3-86 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.[114] Table 3-87 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 2019, using unadjusted cost-based offers for coal units, 53.42 percent of marginal coal units had negative markups. In the first nine months of 2019, using adjusted cost-based offers for coal units, 35.27 percent of marginal coal units had negative markups.

Table 3-86 Percent of marginal units with markup below, above and equal to zero (By fuel type unadjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)			2019 (Jan - Sep)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	49.91%	21.32%	28.76%	53.42%	21.86%	24.72%
Gas	43.61%	10.77%	45.62%	36.65%	8.70%	54.65%
Oil	9.29%	82.26%	8.45%	8.52%	90.56%	0.91%

Table 3-87 Percent of marginal units with markup below, above and equal to zero (By fuel type adjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)			2019 (Jan - Sep)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	17.92%	0.04%	82.04%	35.27%	0.31%	64.43%
Gas	9.38%	0.06%	90.56%	12.83%	0.02%	87.15%
Oil	0.58%	0.00%	99.42%	6.85%	0.00%	93.15%

Figure 3-58 shows the frequency distribution of hourly markups for all gas units offered in the first nine months of 2018 and 2019 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.[115] Of the gas units offered in the PJM market in the first nine months of 2019, nearly 25.0 percent of gas unit-hours had a maximum markup that was negative. More than 10.9 percent of gas fired unit-hours had a maximum markup above $100 per MWh.

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

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

Figure 3-58 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: January through September, 2018 and 2019

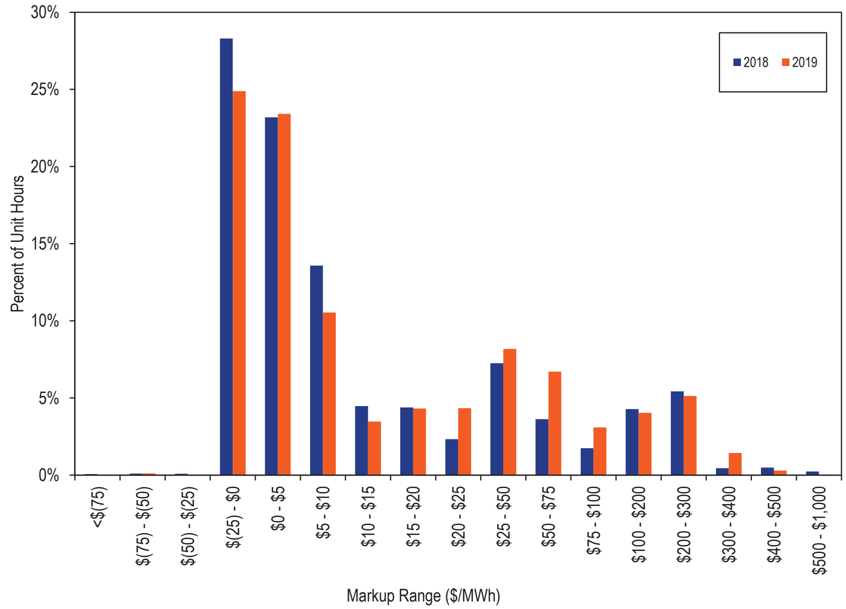


Figure 3-59 shows the frequency distribution of hourly markups for all coal units offered in the first nine months of 2018 and 2019 using unadjusted cost-based offers. Of the coal units offered in the PJM market in the first nine months of 2019, nearly 40.1 percent of coal unit-hours had a maximum markup that was negative or equal to zero.

Figure 3-59 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: January through September, 2018 and 2019

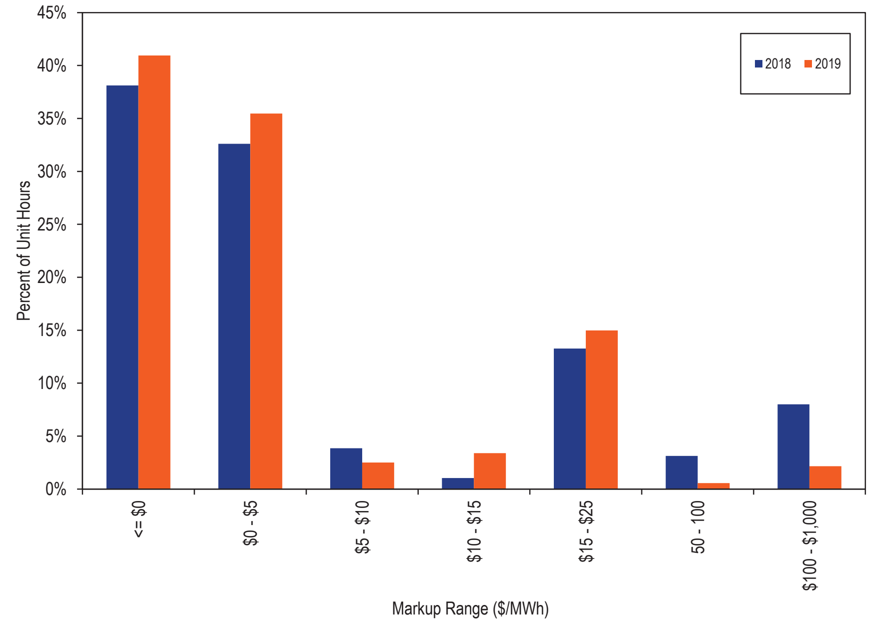
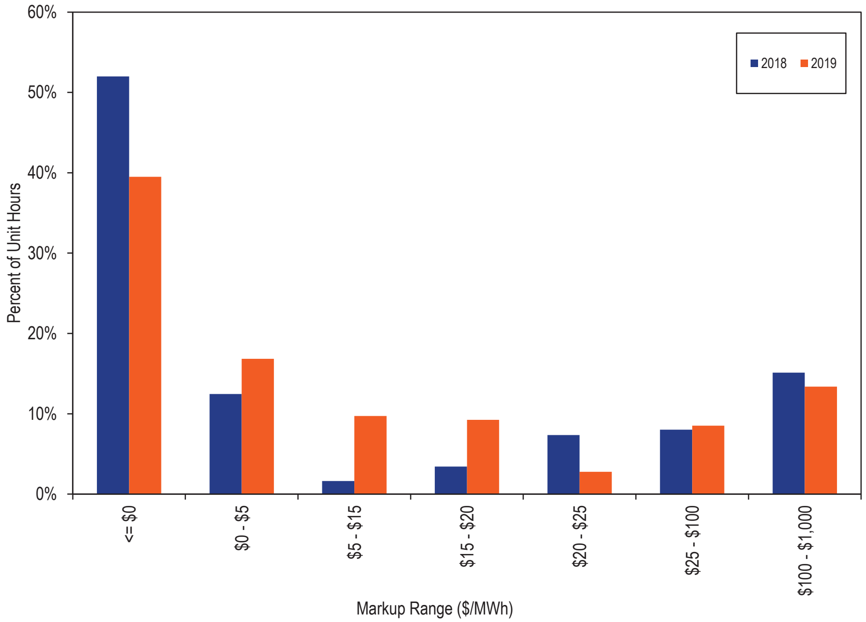


Figure 3-60 shows the frequency distribution of hourly markups for all offered oil units in the first nine months of 2018 and 2019 using unadjusted cost-based offers. Of the oil units offered in the PJM market in the first nine months of 2019, nearly 39.6 percent of oil unit-hours had a maximum markup that was negative or equal to zero. More than 13 percent of oil fired unit-hours had a maximum markup above $100 per MWh.

Figure 3-60 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: January through September, 2018 and 2019

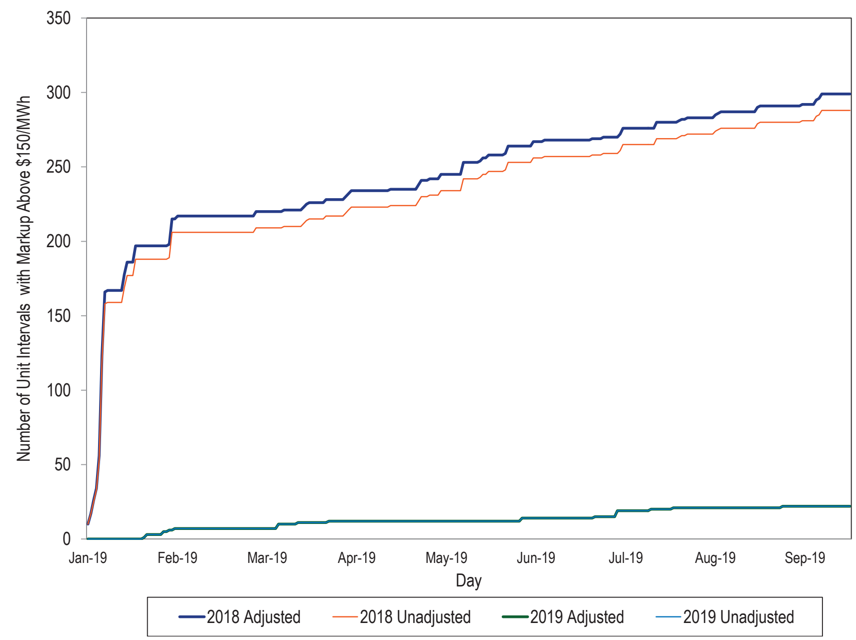


The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion 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 3-61 shows the number of marginal unit intervals in the first nine months of 2019 and 2018 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 3-61 Cumulative number of unit intervals with markups above $150 per MWh: January through September, 2018 and 2019



Day-Ahead Markup Index

Table 3-88 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 2019, 98.4 percent of marginal generating units had offer prices less than $50 per MWh. The average dollar markups of units with offer prices less than $25 was positive ($0.48 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $25 and $50 was positive ($1.38 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 January through September, 2018 and 2019, 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 2019 was about $90 per MWh while the highest markup in the first nine months of 2018 was about $200 per MWh.

Table 3-88 Average day-ahead marginal unit markup index (By offer price category, unadjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)			2019 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.04	$0.19	54.9%	0.11	$0.48	72.2%
$25 to $50	0.10	$3.33	40.4%	0.05	$1.38	26.2%
$50 to $75	0.27	$14.82	2.1%	0.17	$9.28	0.9%
$75 to $100	0.28	$21.98	0.7%	0.35	$32.13	0.1%
$100 to $125	0.02	$1.85	0.4%	0.52	$53.65	0.1%
$125 to $150	0.07	$8.99	0.6%	0.32	$45.31	0.1%
>= $150	0.08	$14.98	1.0%	0.06	$10.11	0.4%

Table 3-89 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 2019, 0.1 percent of marginal generating units had offers between $75 and $100 per MWh, and the average dollar markup and the average markup index were both positive. The average markup index increased from 0.13 in the first nine months of 2018, to 0.19 in the first nine months of 2019 in the offer price category less than $25.

Table 3-89 Average day-ahead marginal unit markup index (By offer price category, adjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)			2019 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.13	$1.90	54.9%	0.19	$2.16	72.2%
$25 to $50	0.18	$5.90	40.4%	0.13	$3.91	26.2%
$50 to $75	0.33	$18.55	2.1%	0.24	$13.53	0.9%
$75 to $100	0.34	$27.57	0.7%	0.41	$37.34	0.1%
$100 to $125	0.11	$11.80	0.4%	0.56	$57.92	0.1%
$125 to $150	0.15	$20.16	0.6%	0.38	$53.81	0.1%
>= $150	0.16	$32.32	1.0%	0.14	$26.18	0.4%

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.

Cost-based offers in PJM affect all aspects of the PJM energy market. Cost-based offers affect prices when units are committed and dispatched on their cost-based offers. In the first nine months of 2019, 9.3 percent of the marginal units set prices based on cost-based offers, 1.0 percentage points less than in the first nine months of 2018.

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 in the PJM market rules is not 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

Short run marginal costs are the only costs relevant to competitive offers in the energy market. Specifically, the competitive energy offer level is the short run marginal cost of production. The current PJM market rules distinguish costs includable in cost-based energy offers from costs includable in cost-based capacity market offers based on whether costs are directly related to energy production. The rules do not provide a clear standard. Energy production is the sole purpose of a power plant. Therefore, all costs, including the sunk costs, are directly related to energy production. This current ambiguous criterion is incorrect and, in addition, allows for multiple interpretations, which could lead to tariff violations. The incorrect rules will lead to higher energy market prices and higher uplift.

There are three types of costs identified under PJM rules as of April 15, 2019: variable costs, avoidable costs, and fixed costs. The criterion for whether a generator may include a cost in an energy market cost-based offer is that the cost is "directly related to electric production."[116]

Variable costs are comprised of short run marginal costs and avoidable costs that are directly related to electric production. Short run marginal costs are the 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, emission allowance costs, operating costs, and energy market opportunity costs.[117]

Avoidable costs are annual costs that would be avoided if energy were not produced over an annual period. The PJM rules divide avoidable costs into those that are directly related to electric production and those not directly related to electric production. The distinction is ambiguous at best. PJM includes overhaul and maintenance costs and overtime staffing costs in costs related to electric production. PJM includes taxes, preventative maintenance to auxiliary equipment, and pipeline reservation charges in costs not related to electric production.

116 See PJM Interconnection L.L.C., 167 FERC ¶ 61,030 (April 15, 2019).
117 See PJM Operating Agreement Schedule 2 (a)

Fixed costs are costs associated with an investment in a facility including the return on and of capital.

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

Fuel Cost Policies

Fuel cost policies (FCP) 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

Table 3-90 shows the status of all Fuel Cost Policies as of September 30, 2019. As of September 30, 2019, 1,135 units (88 percent) had an FCP passed by the MMU, zero units had an FCP under the MMU review (submitted) and 162 units (12 percent) had an FCP failed by the MMU. The number of units with fuel cost policies failed by the MMU included units with 27,536 MW. All units had an FCP approved by PJM. As of September 30, 2019, one unit had FCPs under PJM's review. The number of units with fuel cost policies passed by the MMU increased one percentage point from 87 percent in 2018 Annual Fuel Cost Policy Review to 88 percent as of September 30, 2019.

Table 3-90 FCP Status: September 30, 2019

	MMU Status			
PJM Status	Pass	Submitted	Fail	Total
Submitted	0	0	0	0
Under Review	1	0	0	1
Customer Input Required	0	0	0	0
Approved	1,134	0	162	1,296
Revoked	0	0	0	0
Expired	0	0	0	0
Total	1,135	0	162	1,297

The MMU performed a detailed review of every FCP. PJM approved the FCPs that the MMU passed. PJM approved every FCP failed by the MMU.

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:[118] Verifiable means that the FCP must provide that a market seller 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 means that the FCP must document a standardized method or methods for calculating fuel costs including objective triggers for each method.[119] PJM and FERC did not agree that Fuel Cost Policies should be algorithmic:[120] Algorithmic means that the FCP must use a set of defined, logical steps, analogous to a recipe, to calculate the fuel costs. 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').[121]

FCPs are not verifiable and systematic if they are not algorithmic. The natural gas FCPs failed by the MMU and approved by PJM are not verifiable and systematic.

Not all FCPs approved by PJM met the standard of the PJM tariff. The tariff standards that some Fuel Cost Policies did not meet are:[122] accuracy (reflect applicable costs accurately); procurement practices (provide information sufficient for the verification of the market seller's fuel procurement practices where relevant); fuel contracts (reflect the market seller's applicable commodity and/or transportation contracts where it holds such contracts).

The MMU failed FCPs not related to natural gas submitted by some market sellers because they do not accurately describe the short run marginal cost of fuel. Some policies include contractual terms (in $ per MWh or in $ per MMBtu) that do not reflect the actual cost of fuel. The MMU determined that the terms used in these policies do not reflect the cost of fuel based on the information provided by the market sellers and information gathered by the MMU for similar resources.

The MMU failed the remaining FCPs because they do not accurately reflect the cost of natural gas. The main issues identified by the MMU in the natural gas policies were:

- Unverifiable cost estimates. Some of these policies include options under which the estimate of the natural gas commodity cost would be calculated by the market seller without specifying a verifiable, objective, quantitative method. For example, some FCPs specify that the source of the natural gas cost would be communications with traders within the market seller's organization. A fuel cost from discretionary and undocumented decision making within the market seller's organization is not verifiable. The point of FCPs is to eliminate such practices as the basis for fuel costs, as most companies have done. Verifiability requires that fuel cost estimates be transparently derived from market information and that PJM or the MMU could reproduce the same fuel cost estimates after the fact by applying the methods documented in the FCP to the same inputs. Verifiable is a key requirement of an FCP. If it is not verifiable, an FCP is meaningless and has no value. Unverifiable fuel costs permit the exercise of market power.
- Use of available market information that results in inaccurate expected costs. Some market sellers include the use of offers to sell natural gas on ICE as the sole basis for the cost of natural gas. An offer to sell is generally not an accurate indication of the expected fuel cost. The price of uncleared offers on the exchange generally exceeds the price of cleared transactions, often by a wide margin. Use of sell offers alone is equivalent to using the supply curve alone to determine the market price of a good without considering the demand curve. It is clearly incorrect.

The FCPs that failed the MMU's evaluation also fail to meet the standards defined in the PJM tariff. PJM should not have approved inaccurate Fuel Cost Policies.

118 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.
119 Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) ("September 16th Filing") at P 8.
120 October 7th Filing at P12; 158 FERC ¶ 61,133 at P 57 (2017) ("February 3rd Order").
121 September 16th Filing at P 8.
122 See PJM Operating Agreement Schedule 2 § 2.3 (a).

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 nonzero cost-based offers. PJM should set to zero the cost-based offers of units without an approved Fuel Cost Policy.

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.[123] Penalties became effective May 15, 2017.

In the first nine months of 2019, 48 penalty cases were identified, 44 resulted in assessed cost-based offer penalties, zero resulted in disagreement between the MMU and PJM, and four remain pending PJM's determination. These cases were from 48 units owned by 15 different companies. Table 3-92 shows the penalties by the year in which participants were notified.

123 158 FERC ¶ 61,133 (2017) ("February 3rd Order").

Table 3-91 Cost-based offer penalty cases by year notified: 2017 through 2019

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	187	159	26	2	137	35
2019	48	44	0	4	48	15
Total	292	259	27	6	231	50

Since 2017, 292 penalty cases have been identified, 259 resulted in assessed cost-based offer penalties, 27 resulted in disagreement between the MMU and PJM, and six remain pending PJM's determination. The 259 cases were from 231 units owned by 50 different companies. The total penalties were $2.2 million, charged to units that totaled 59,189 available MW. The average penalty was $1.72 per available MW.[124] Table 3-92 shows the total cost-based offer penalties since 2017 by year.

Table 3-92 Cost-based offer penalties by year: May 2017 through September 2019

Year	Number of units	Number of companies	Penalties	Average Available Capacity Charged (MW)	Average Penalty ($/MW)
2017	92	20	$556,826	16,930	$1.56
2018	125	33	$1,257,292	26,054	$2.28
2019	48	13	$394,524	16,204	$1.05
Total	265	50	$2,208,642	59,189	$1.72

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

124 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.

description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers.

Variable Operating and Maintenance Costs

PJM Manual 15 and the PJM Operating Agreement Schedule 2 include rules related to VOM costs. On October 29, 2018, PJM filed tariff revisions changing the rules related to VOM costs.[125] The changes proposed by PJM attempted to clarify the rules. The proposed rules defined all costs directly related to electricity production as includable in cost-based offers. This also included the long term maintenance costs of combined cycles and combustion turbines, which had been explicitly excluded in PJM Manual 15.

On April 15, 2019, FERC accepted PJM's filing order, subject to revisions requested by FERC.[126] On October 28, 2019, FERC issued a final order accepting PJM's compliance filing.[127] Regardless of the changes, the rules remain unclear and are now inconsistent with economic theory. The purpose of cost-based energy offers is to prevent the exercise of market power in the PJM energy market. PJM administers market power mitigation in the energy market by replacing a generator's market-based offer with its cost-based offer when the generator owner fails the structural test for local market power, the Three Pivotal Supplier ("TPS") test, or is required for reliability. The effectiveness of market power mitigation in delivering competitive market outcomes is based entirely on cost-based offers as the measure of the competitive offer level. When market power is not mitigated, energy prices exceed the competitive level, uplift payments exceed the efficient level, and economic withholding allows generators to collect capacity payments without running, while raising prices for other generators and for load. The competitive offer level is the short run marginal cost of the generator for the relevant market hour.

Maintenance costs are not short run marginal costs. Generators perform maintenance during outages. Generators do not perform maintenance in the short run, while operating the generating unit. Generators do not perform maintenance in real time to increase the output of a unit. Some maintenance costs are correlated with the historic operation of a generator. Correlation between operating hours or starts and maintenance expenditures over a long run, multiyear time frame does not indicate the necessity of any specific maintenance expenditure to produce power in the short run.

A generating unit does not consume a defined amount of maintenance parts and labor in order to start. A generating unit does not consume a defined amount of maintenance parts and labor in order to produce an additional MWh. Maintenance events do not occur in the short run. The company cannot optimize its maintenance costs in the short run.

In the nine six months of 2019, VOM costs reviewed and approved by PJM for 2019 remained in place based on the previous rules. In June 2019, PJM began reviewing revised operating costs and maintenance costs based on the April 15th Order. Operating and maintenance costs approved by PJM in 2019 based on the April 15th Order become effective within seven days of approval.

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.[128]

125 See PJM Interconnection Maintenance Adder Revisions to the Amended and Restated Operating Agreement, L.L.C., Docket No. EL19-8-000.
126 167 FERC ¶ 61,030.
127 168 FERC ¶ 61,134.

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

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

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 steam turbine breaker close 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)

The new rules for determining the qualification of a unit as an FMU or AU became effective November 1, 2014. 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 units eligible for an FMU or AU adder for the period between December 2014 and August 2019.[129] One unit qualified for an FMU adder for the month of September 2019.

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.

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.

Market Performance

Ownership of Marginal Resources

Table 3-93 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.[130] 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 2019, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. In the first nine months of 2019, the offers of one company resulted in 13.7 percent of the real-time, load-weighted PJM system LMP and the offers of the top four companies resulted in 39.7 percent of the real-time, load-weighted, average PJM system LMP. During 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 offers of the top four companies resulted in 39.1 percent of the real-time, load-weighted, average PJM system LMP. In the first nine months of 2019, the offers of one company resulted in 15.2 percent of the peak hour real-time, load-weighted 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. 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.

129 For a definition of FMUs and AUs, and for historical FMU/AU results, see the 2018 State of the Market Report for PJM, Volume 2, Section 3, Energy Market, at Frequently Mitigated Units (FMU) and Associated Units (AU).
130 See the MMU Technical Reference for PJM Markets, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table 3-93 Marginal unit contribution to real-time, load-weighted LMP (By parent company): January through September, 2018 and 2019

2018 (Jan - Sep)						2019 (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	13.3%	13.3%	1	12.1%	12.1%	1	13.7%	13.7%	1	15.2%	15.2%
2	10.0%	23.3%	2	10.0%	22.1%	2	10.7%	24.4%	2	11.2%	26.4%
3	8.6%	31.9%	3	8.0%	30.1%	3	9.1%	33.5%	3	7.9%	34.3%
4	7.2%	39.1%	4	7.5%	37.6%	4	6.2%	39.7%	4	5.4%	39.7%
5	6.6%	45.7%	5	6.0%	43.6%	5	5.2%	44.9%	5	5.0%	44.7%
6	4.7%	50.5%	6	5.5%	49.0%	6	4.6%	49.5%	6	4.2%	48.9%
7	4.7%	55.1%	7	5.4%	54.5%	7	4.5%	54.0%	7	3.9%	52.8%
8	4.5%	59.7%	8	4.9%	59.4%	8	4.2%	58.2%	8	3.9%	56.7%
9	4.1%	63.8%	9	3.7%	63.1%	9	3.7%	61.9%	9	3.8%	60.5%
Other (79 companies)	36.2%	100.0%	Other (76 companies)	36.9%	100.0%	Other (70 companies)	38.1%	100.0%	Other (67 companies)	39.5%	100.0%

Table 3-94 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[131] 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 2019, the offers of one company contributed 10.0 percent of the day-ahead, load-weighted, PJM system LMP and that the offers of the top four companies contributed 30.1 percent of the day-ahead, load-weighted, average, PJM system LMP. 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 offers of the top four companies contributed 30.2 percent of the day-ahead, load-weighted, average PJM system LMP.

Table 3-94 Marginal resource contribution to day-ahead, load-weighted LMP (By parent company): January through September, 2018 and 2019

2018 (Jan - Sep)						2019 (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	12.1%	12.1%	1	14.1%	14.1%	1	10.0%	10.0%	1	12.1%	12.1%
2	7.2%	19.3%	2	7.1%	7.1%	2	7.8%	17.8%	2	6.1%	18.3%
3	6.1%	25.4%	3	5.4%	5.4%	3	6.2%	24.0%	3	5.8%	24.1%
4	4.8%	30.2%	4	5.0%	5.0%	4	6.1%	30.1%	4	5.3%	29.4%
5	4.4%	34.6%	5	5.0%	5.0%	5	4.6%	34.7%	5	5.1%	34.5%
6	4.2%	38.8%	6	4.1%	4.1%	6	3.6%	38.3%	6	3.6%	38.1%
7	3.8%	42.6%	7	3.9%	3.9%	7	3.5%	41.8%	7	3.4%	41.5%
8	3.7%	46.4%	8	3.5%	3.5%	8	3.4%	45.2%	8	3.1%	44.7%
9	3.6%	50.0%	9	3.1%	3.1%	9	3.3%	48.5%	9	3.1%	47.8%
Other (161 companies)	50.0%	100.0%	Other (146 companies)	48.8%	48.8%	Other (142 companies)	51.5%	100.0%	Other (133 companies)	52.2%	100.0%

131 Id.

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.[132] 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 3-95 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 decreased from $7.90 per MWh in the first nine months of 2018 to $4.07 per MWh in the first nine months of 2019. The adjusted markup contribution of coal units in the first nine months of 2019 was $0.93 per MWh. The adjusted markup component of gas fired units in the first nine months of 2019 was $3.17 per MWh, a decrease of $1.76 per MWh from the first nine months of 2018. The markup component of wind units was less than $0.0 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, 92.9 percent had negative offer prices.

132 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 3-95 Markup component of real-time, load-weighted, average LMP by primary fuel type and unit type: January through September, 2018 and 2019[133]

		2018 (Jan - Sep)		2019 (Jan - Sep)	
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	$1.36	$2.25	$0.06	$0.93
Gas	CC	$2.94	$4.15	$1.86	$2.85
Gas	CT	$0.34	$0.67	$0.20	$0.39
Gas	RICE	$0.00	$0.01	$0.02	$0.03
Gas	Steam	$0.02	$0.10	($0.16)	($0.11)
Landfill Gas	CT	$0.00	$0.00	($0.00)	($0.00)
Landfill Gas	RICE	$0.00	$0.00	$0.00	$0.00
Municipal Waste	CT	$0.00	$0.00	$0.00	$0.00
Municipal Waste	RICE	$0.00	$0.00	$0.00	$0.00
Oil	CC	$0.20	$0.22	($0.00)	$0.00
Oil	CT	$0.07	$0.23	$0.00	$0.00
Oil	RICE	$0.00	$0.00	$0.00	$0.00
Oil	Steam	$0.13	$0.17	($0.03)	($0.03)
Other	Steam	$0.09	$0.09	($0.00)	($0.00)
Uranium	Steam	$0.00	$0.00	$0.00	$0.00
Wind	Wind	$0.01	$0.01	($0.00)	($0.00)
Total		$5.17	$7.90	$1.95	$4.07

Markup Component of Real-Time Price

Table 3-96 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-97 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 2019, when using unadjusted cost-based offers, $1.95 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-based offers, $4.07 per MWh of the PJM real-time load-weighted, average LMP was attributable to markup. In the first nine months of 2019, the peak markup component was highest in July, $4.91 per MWh using unadjusted cost-based offers and peak markup component was highest in July, $7.25 per MWh using adjusted cost-based offers. This corresponds to 14.1 percent and 20.9 percent of the real-time peak load-weighted average LMP in July.

133 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Table 3-96 Monthly markup components of real-time load-weighted LMP (Unadjusted): 2018 and 2019

	2018			2019		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$9.32	$11.70	$6.90	$2.11	$1.49	$2.70
Feb	$1.47	$0.95	$1.97	$2.34	$1.63	$3.05
Mar	$4.89	$2.58	$7.15	$2.27	$1.82	$2.74
Apr	$5.77	$3.47	$8.03	$1.59	$0.81	$2.27
May	$5.21	$1.57	$8.45	$1.41	$0.56	$2.19
Jun	$2.93	$1.83	$3.95	$1.56	$1.24	$1.89
Jul	$4.84	$1.50	$8.01	$3.58	$2.12	$4.91
Aug	$4.81	$1.94	$7.12	$0.87	$0.99	$0.77
Sep	$6.55	$3.71	$9.63	$1.46	$0.78	$2.14
Oct	$3.93	$2.28	$5.32			
Nov	$2.70	$1.21	$4.16			
Dec	$1.45	$0.91	$2.07			
Total	$4.56	$2.93	$6.13	$1.95	$1.31	$2.56

Table 3-97 Monthly markup components of real-time load-weighted LMP (Adjusted): 2018 and 2019

	2018			2019		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$15.04	$17.70	$12.34	$4.66	$3.81	$5.48
Feb	$3.64	$2.96	$4.32	$4.52	$3.72	$5.33
Mar	$7.24	$4.80	$9.63	$4.53	$3.99	$5.11
Apr	$8.24	$5.74	$10.69	$3.60	$2.67	$4.42
May	$7.38	$3.48	$10.87	$3.38	$2.33	$4.33
Jun	$5.04	$3.75	$6.26	$3.42	$2.89	$3.94
Jul	$7.21	$3.61	$10.62	$5.73	$4.06	$7.25
Aug	$7.24	$4.16	$9.71	$2.83	$2.60	$3.03
Sep	$8.92	$5.85	$12.25	$3.50	$2.58	$4.42
Oct	$6.36	$4.48	$7.94			
Nov	$5.57	$3.88	$7.24			
Dec	$4.14	$3.47	$4.92			
Total	$7.29	$5.51	$8.99	$4.07	$3.23	$4.86

Hourly Markup Component of Real-Time Prices

Figure 3-62 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in the first nine months of 2019 and 2018. Figure 3-63 shows the markup contribution to the hourly load-weighted LMP using adjusted cost-based offers in the first nine months of 2019 and 2018. 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 3-62 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): 2018 and 2019

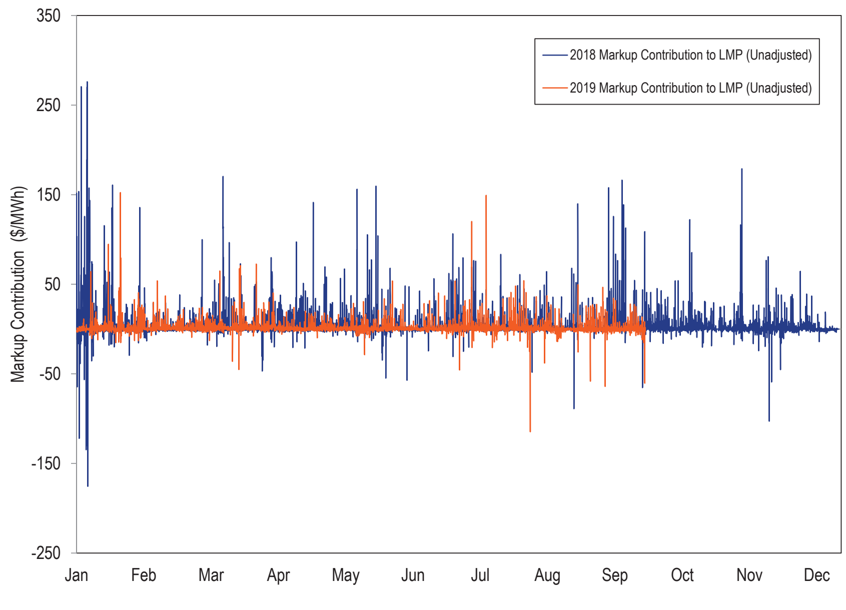
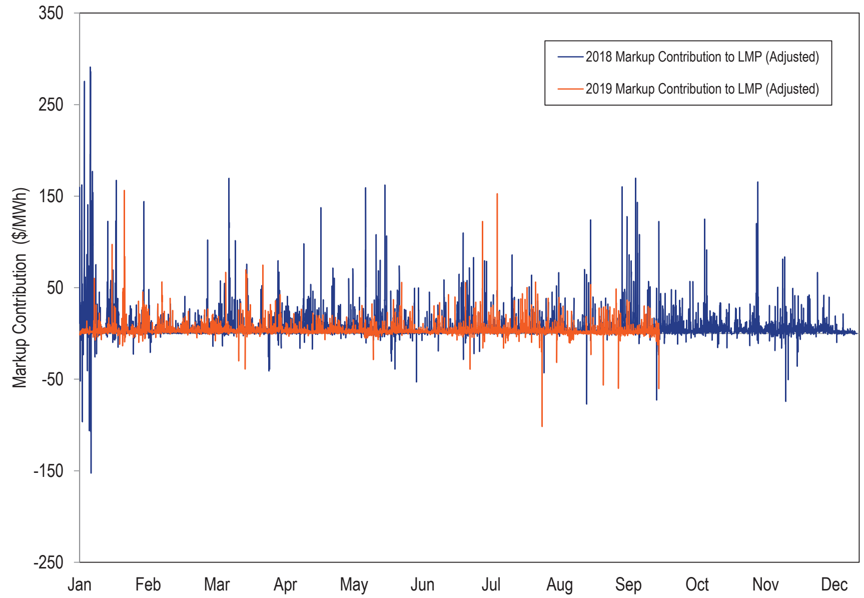


Figure 3-63 Markup contribution to real-time hourly load-weighted LMP (Adjusted): 2018 and 2019



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 2018 and 2019 in Table 3-98 and for adjusted offers in Table 3-99[134]. The smallest zonal all hours average markup component using unadjusted offers in the first nine months of 2019, was in the ComEd Control Zone, 1.54 per MWh, while the highest was in the DPL Control Zone, $2.48 per MWh. The smallest zonal on peak average markup component using unadjusted offers in the first nine months of 2019, was in the ComEd Control Zone, 2.13 per MWh, while the highest was in the DAY Control Zone, $2.98 per MWh.

134 A marginal unit's offer price affects LMPs in the entire PJM market. The markup component of average zonal real-time price is based on offers of units located within the zone and units located outside the transmission zone.

Table 3-98 Average real-time zonal markup component (Unadjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)			2019 (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	$4.64	$3.46	$5.76	$2.32	$1.87	$2.77
AEP	$4.91	$3.32	$6.45	$1.89	$1.18	$2.58
APS	$5.62	$3.70	$7.48	$1.87	$1.23	$2.50
ATSI	$6.18	$3.62	$8.60	$1.99	$1.27	$2.68
BGE	$6.92	$4.19	$9.54	$2.05	$1.19	$2.89
ComEd	$3.64	$1.68	$5.47	$1.54	$0.90	$2.13
DAY	$5.21	$3.22	$7.04	$2.14	$1.22	$2.98
DEOK	$5.33	$3.52	$7.07	$1.99	$1.15	$2.78
DLCO	$6.41	$3.87	$8.85	$2.00	$1.27	$2.71
DPL	$5.15	$3.75	$6.49	$2.48	$2.12	$2.84
Dominion	$6.33	$4.86	$7.75	$1.86	$1.23	$2.47
EKPC	$4.82	$3.73	$5.93	$1.87	$1.15	$2.58
JCPL	$4.54	$3.45	$5.51	$2.21	$1.71	$2.68
Met-Ed	$4.79	$3.29	$6.18	$1.94	$1.45	$2.38
OVEC	NA	NA	NA	$1.64	$0.97	$2.39
PECO	$4.50	$3.04	$5.85	$2.39	$2.07	$2.68
PENELEC	$5.14	$3.21	$6.94	$1.82	$1.25	$2.36
PPL	$4.30	$2.81	$5.69	$1.99	$1.51	$2.44
PSEG	$4.29	$3.20	$5.31	$2.24	$1.70	$2.76
Pepco	$6.16	$4.10	$8.09	$1.94	$1.20	$2.64
RECO	$4.76	$3.28	$6.02	$2.02	$1.55	$2.44

Table 3-99 Average real-time zonal markup component (Adjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)			2019 (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	$7.24	$5.94	$8.49	$4.27	$3.66	$4.87
AEP	$7.57	$5.83	$9.26	$4.04	$3.13	$4.92
APS	$8.51	$6.46	$10.51	$4.04	$3.20	$4.86
ATSI	$8.91	$6.11	$11.56	$4.16	$3.22	$5.04
BGE	$10.12	$7.23	$12.88	$4.40	$3.32	$5.44
ComEd	$5.95	$3.85	$7.92	$3.55	$2.69	$4.36
DAY	$7.86	$5.68	$9.87	$4.36	$3.23	$5.41
DEOK	$7.87	$5.91	$9.75	$4.13	$3.09	$5.12
DLCO	$9.14	$6.33	$11.82	$4.13	$3.19	$5.04
DPL	$8.17	$6.55	$9.72	$4.51	$3.99	$5.01
Dominion	$9.45	$7.99	$10.88	$4.09	$3.26	$4.91
EKPC	$7.38	$6.12	$8.66	$4.03	$3.13	$4.91
JCPL	$7.23	$6.03	$8.31	$4.20	$3.53	$4.82
Met-Ed	$7.39	$5.75	$8.90	$3.98	$3.29	$4.61
OVEC	NA	NA	NA	$3.70	$2.85	$4.65
PECO	$7.17	$5.58	$8.64	$4.33	$3.84	$4.78
PENELEC	$7.81	$5.67	$9.81	$3.89	$3.13	$4.59
PPL	$6.92	$5.36	$8.37	$3.96	$3.30	$4.57
PSEG	$6.92	$5.70	$8.05	$4.21	$3.51	$4.87
Pepco	$9.32	$7.16	$11.35	$4.23	$3.27	$5.14
RECO	$7.34	$5.71	$8.72	$3.96	$3.35	$4.50

Markup by Real-Time Price Levels

Table 3-100 shows the markup contribution to the LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system wide load-weighted average LMP was in the identified price range.

Table 3-100 Real-time markup contribution (By PJM load-weighted LMP category, unadjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)		2019 (Jan - Sep)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $25	($0.35)	40.1%	($0.03)	61.0%
$25 to $50	$3.55	47.4%	$2.77	35.3%
$50 to $75	$18.66	6.5%	$16.07	2.5%
$75 to $100	$22.28	2.1%	$23.33	0.6%
$100 to $125	$29.21	1.5%	$21.82	0.2%
$125 to $150	$21.02	0.7%	$26.17	0.1%
>= $150	$43.56	1.7%	$28.96	0.3%

Table 3-101 Real-time markup contribution (By PJM load-weighted LMP category, adjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)		2019 (Jan - Sep)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $25	$1.60	40.2%	$1.82	61.0%
$25 to $50	$6.12	47.4%	$5.20	35.3%
$50 to $75	$21.86	6.5%	$18.95	2.5%
$75 to $100	$27.19	2.1%	$27.01	0.6%
$100 to $125	$35.77	1.5%	$25.82	0.2%
$125 to $150	$29.62	0.7%	$29.54	0.1%
>= $150	$55.96	1.7%	$31.35	0.3%

Markup by Company

Table 3-102 shows the markup contribution based on the unadjusted cost-based offers and adjusted cost-based offers to real-time, load-weighted average LMP by individual marginal resource owners. The markup contribution of each marginal resource to price at each load bus is calculated for each five-minute interval, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. In the first nine months of 2019, when using unadjusted cost-based offers, the markup of one company accounted for 2.3 percent of the load-weighted average LMP, the markup of the top five companies accounted for 6.0 percent of the load-weighted average LMP and the markup of all companies accounted for 7.1 percent of the load-weighted average LMP. In the first nine months of 2018, when using unadjusted cost-based offers, the markup of one company accounted for 3.0 percent of the load-weighted average LMP, the markup of the top five companies accounted for 9.1 percent of the load-weighted average LMP and the markup of all companies accounted for 13.1 percent of the load-weighted average LMP. The top five companies' markup contribution to the load-weighted average LMP and the dollar values of their markup decreased in the first nine months of 2019. The markup contribution to the load-weighted average LMP and share of the markup contribution to the load-weighted average LMP also decreased in the first nine months of 2019.

Table 3-102 Markup component of real-time, load-weighted, average LMP by Company: January through September, 2018 and 2019

	2018 (Jan - Sep)				2019 (Jan - Sep)			
	Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)		Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)	
	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP
Top 1 Company	$1.18	3.0%	$1.53	3.9%	$0.63	2.3%	$0.75	2.7%
Top 2 Companies	$1.94	4.9%	$2.50	6.3%	$0.95	3.5%	$1.39	5.0%
Top 3 Companies	$2.68	6.8%	$3.33	8.4%	$1.22	4.4%	$1.91	6.9%
Top 4 Companies	$3.21	8.1%	$4.02	10.2%	$1.49	5.4%	$2.29	8.3%
Top 5 Companies	$3.58	9.1%	$4.48	11.4%	$1.67	6.0%	$2.54	9.2%
All Companies	$5.17	13.1%	$7.90	20.0%	$1.95	7.1%	$4.07	14.7%

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 3-103. INC, DEC and up to congestion transactions (UTC) have zero markups. INCs were 12.9 percent of marginal resources and DECs were 18.4 percent of marginal resources in the first nine months of 2019. 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 63.9 percent in the first nine months of 2018 to 57.7 percent in the first nine months of 2019 as the result of a FERC order issued on February 20, 2018, and implemented on February 22, 2018.[135] 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 3-103 shows the markup component of LMP for marginal generating resources. Generating resources were only 10.9 percent of marginal resources in the first nine months of 2019. Using adjusted cost-based offers, the markup component of LMP for marginal generating resources decreased for coal fired steam units from $1.36 to $0.39 and decreased for gas fired CT units from $0.13 to $0.02. The markup component of LMP for coal fired steam units decreased from $0.65 in the first nine months of 2018 to -$0.32 in the first nine months of 2019 using unadjusted cost-based offers

135 162 FERC ¶ 61,139 (2018).

Table 3-103 Markup component of day-ahead, load-weighted, average LMP by primary fuel type and technology type: January through September, 2018 and 2019

		2018 (Jan - Sep)			2019 (Jan - Sep)		
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency
Coal	Steam	$0.65	$1.36	43.7%	($0.32)	$0.39	41.6%
Gas	CT	$0.05	$0.13	3.4%	$0.01	$0.02	2.0%
Gas	RICE	$0.00	$0.00	0.7%	($0.00)	($0.00)	0.5%
Gas	Steam	$0.56	$1.20	46.9%	$0.87	$1.42	53.2%
Municipal Waste	RICE	$0.00	$0.00	0.0%	$0.00	$0.00	0.1%
Oil	CT	$0.00	$0.00	0.5%	$0.00	$0.00	0.5%
Oil	RICE	$0.00	$0.00	0.0%	$0.00	$0.00	0.0%
Oil	Steam	($0.01)	$0.10	0.8%	($0.01)	($0.01)	0.1%
Other	Solar	$0.00	$0.00	0.3%	$0.00	$0.00	0.2%
Other	Steam	($0.00)	($0.00)	0.1%	($0.00)	($0.00)	0.1%
Uranium	Steam	$0.00	$0.00	1.5%	$0.00	$0.00	0.7%
Water	Hydro	$0.00	$0.00	0.0%	$0.00	$0.00	0.0%
Wind	Wind	$0.01	$0.01	2.0%	$0.13	$0.13	1.1%
Total		$1.26	$2.81	100.0%	$0.67	$1.95	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 3-104 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted cost-based offers. In the first nine months of 2019, when using unadjusted cost-based offers, $0.67 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first nine months of 2019, the peak markup component was highest in July, $4.14 per MWh using unadjusted cost-based offers.

Table 3-104 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January 2018 through September 2019

	2018			2019		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$3.15	$4.21	$2.08	$0.78	$1.68	($0.16)
Feb	$0.87	$1.65	$0.05	$0.60	$0.80	$0.41
Mar	$0.46	$0.61	$0.31	$0.65	$0.99	$0.32
Apr	$1.09	$1.55	$0.62	$0.15	$0.30	($0.03)
May	$0.83	$1.22	$0.40	$0.11	$0.13	$0.09
Jun	$0.29	$0.67	($0.13)	$0.45	$0.38	$0.53
Jul	$1.39	$2.50	$0.20	$2.50	$4.14	$0.66
Aug	$1.03	$1.76	$0.11	$0.39	$0.44	$0.34
Sep	$1.96	$3.14	$0.85	($0.09)	($0.28)	$0.09
Oct	$1.21	$1.56	$0.80			
Nov	$1.26	$1.98	$0.53			
Dec	$0.81	$1.37	$0.33			
Annual	$1.22	$1.88	$0.53	$0.67	$1.05	$0.26

Table 3-105 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: January 2018 through September 2019

	2018			2019		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$6.31	$7.41	$5.21	$2.45	$3.33	$1.55
Feb	$2.46	$3.32	$1.57	$2.09	$2.32	$1.87
Mar	$1.78	$1.89	$1.67	$2.01	$2.27	$1.77
Apr	$2.17	$2.51	$1.82	$1.24	$1.25	$1.23
May	$2.00	$2.25	$1.72	$1.29	$1.17	$1.43
Jun	$1.75	$2.01	$1.47	$1.64	$1.62	$1.67
Jul	$2.73	$3.70	$1.70	$3.67	$5.17	$2.00
Aug	$2.36	$2.88	$1.71	$1.55	$1.48	$1.64
Sep	$3.16	$4.17	$2.22	$1.06	$0.81	$1.32
Oct	$2.44	$2.66	$2.17			
Nov	$2.75	$3.21	$2.28			
Dec	$2.69	$3.24	$2.20			
Annual	$2.76	$3.31	$2.19	$1.95	$2.26	$1.62

Table 3-105 shows the markup component of average prices and of average monthly on peak and off peak prices using adjusted cost-based offers. In the first nine months of 2019, when using adjusted cost-based offers, $1.95 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first nine months of 2019, the peak markup component was highest in July, $5.17 per MWh using adjusted cost-based offers.

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 3-106. The markup component of annual average day-ahead price using adjusted cost-based offers is shown for each zone in Table 3-107. The smallest zonal all hours average markup component using adjusted cost-based offers for the first nine months of 2019 was in the ComEd Zone, $1.21 per MWh, while the highest was in the AECO Control Zone, $2.99 per MWh. The smallest zonal on peak average markup using adjusted cost-based offers was in the ComEd Control Zone, $0.98 per MWh, while the highest was in the AECO Control Zone, $3.90 per MWh.

Table 3-106 Day-ahead, average, zonal markup component (Unadjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)			2019 (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	$1.73	$2.49	$0.90	$1.81	$2.82	$0.76
AEP	$1.20	$1.90	$0.47	$0.48	$0.73	$0.21
APS	$1.19	$1.83	$0.53	$0.43	$0.67	$0.18
ATSI	$1.19	$1.76	$0.58	$0.94	$1.61	$0.21
BGE	$0.98	$1.61	$0.31	$0.90	$1.86	($0.11)
ComEd	$0.97	$1.66	$0.24	($0.05)	($0.24)	$0.15
DAY	$1.28	$1.93	$0.57	$1.40	$2.54	$0.15
DEOK	$1.57	$2.55	$0.52	$1.10	$2.01	$0.12
DLCO	$1.22	$1.80	$0.59	$0.65	$1.11	$0.17
Dominion	$1.06	$1.73	$0.38	$0.38	$0.72	$0.02
DPL	$1.49	$2.13	$0.82	$1.23	$1.68	$0.74
EKPC	$1.53	$2.54	$0.51	$0.53	$0.83	$0.23
JCPL	$1.64	$2.32	$0.88	$1.40	$2.04	$0.69
Met-Ed	$1.59	$2.28	$0.83	$0.88	$1.27	$0.44
OVEC	NA	NA	NA	($0.06)	$0.41	($0.46)
PECO	$1.70	$2.48	$0.86	$1.37	$1.99	$0.70
PENELEC	$1.26	$1.95	$0.52	$0.42	$0.42	$0.43
Pepco	$0.94	$1.55	$0.29	$0.45	$0.92	($0.06)
PPL	$1.65	$2.42	$0.83	$1.01	$1.41	$0.58
PSEG	$1.59	$2.23	$0.88	$1.26	$1.81	$0.68
RECO	$1.59	$2.15	$0.93	$1.02	$1.45	$0.53

Table 3-107 Day-ahead, average, zonal markup component (Adjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)			2019 (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	$3.39	$4.07	$2.66	$2.99	$3.90	$2.04
AEP	$2.67	$3.25	$2.06	$1.77	$1.93	$1.60
APS	$2.72	$3.21	$2.21	$1.74	$1.90	$1.56
ATSI	$2.67	$3.12	$2.18	$2.26	$2.86	$1.60
BGE	$2.68	$3.19	$2.13	$2.29	$3.20	$1.33
ComEd	$2.34	$2.98	$1.66	$1.21	$0.98	$1.45
DAY	$2.77	$3.31	$2.18	$2.80	$3.89	$1.60
DEOK	$3.00	$3.92	$2.03	$2.45	$3.30	$1.55
DLCO	$2.61	$3.01	$2.18	$1.91	$2.25	$1.55
Dominion	$2.72	$3.25	$2.17	$1.71	$1.96	$1.44
DPL	$3.12	$3.63	$2.59	$2.42	$2.76	$2.05
EKPC	$3.05	$4.04	$2.06	$1.82	$2.04	$1.60
JCPL	$3.31	$3.91	$2.63	$2.62	$3.16	$2.02
Met-Ed	$3.20	$3.81	$2.54	$2.12	$2.43	$1.77
OVEC	NA	NA	NA	$0.89	$1.18	$0.64
PECO	$3.36	$4.04	$2.64	$2.56	$3.08	$1.99
PENELEC	$2.81	$3.41	$2.14	$1.67	$1.59	$1.76
Pepco	$2.61	$3.10	$2.08	$1.83	$2.27	$1.37
PPL	$3.29	$3.95	$2.59	$2.22	$2.54	$1.88
PSEG	$3.24	$3.78	$2.63	$2.45	$2.88	$1.97
RECO	$3.19	$3.68	$2.62	$2.21	$2.51	$1.87

Markup by Day-Ahead Price Levels

Table 3-108 and Table 3-109 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 3-108 Average, day-ahead markup component (By LMP category, unadjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)		2019 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.13)	32.6%	($0.04)	53.7%
$25 to $50	$0.73	55.9%	$0.35	44.1%
$50 to $75	$0.25	6.1%	$0.28	1.5%
$75 to $100	$0.10	2.2%	$0.03	0.6%
$100 to $125	$0.07	1.2%	$0.02	0.1%
$125 to $150	$0.06	0.8%	$0.02	0.0%
>= $150	$0.17	1.2%	$0.01	0.0%

Table 3-109 Average, day-ahead markup component (By LMP category, adjusted): January through September, 2018 and 2019

	2018 (Jan - Sep)		2019 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$0.29	32.6%	$0.61	53.7%
$25 to $50	$1.52	55.9%	$0.95	44.1%
$50 to $75	$0.33	6.1%	$0.29	1.5%
$75 to $100	$0.16	2.2%	$0.05	0.6%
$100 to $125	$0.13	1.2%	$0.03	0.1%
$125 to $150	$0.10	0.8%	$0.02	0.0%
>= $150	$0.28	1.2%	$0.01	0.0%