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, markup, and price. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2023.

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 56.8 percent of the days in the first nine months of 2023. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM aggregate energy market in the first nine months of 2023 was, on average, unconcentrated by FERC HHI standards. The average HHI was 682 with a minimum of 528 and a maximum of 949. The baseload segment of the supply curve was unconcentrated. The intermediate segment of the supply curve was unconcentrated on average. The peaking segment of the supply curve was highly concentrated. The fact that the average HHI is in the unconcentrated 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. Transmission constraints create the potential for the exercise of local market power. The goal of PJM's application of the three pivotal supplier test is to identify local market power and offer cap to 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 the day-ahead and real-time energy markets, although the behavior of some participants both routinely and during periods of high demand represents economic withholding. The ownership of marginal units is concentrated. The markups of pivotal suppliers in the aggregate market and of many pivotal suppliers in local markets remain unmitigated due to the lack of aggregate market power mitigation and the flawed implementation of offer caps for resources that fail the TPS test. 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, 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 resolved the problems with real-time dispatch and pricing effective November 1, 2021. The implementation of fast start pricing on September 1, 2021, undermined market efficiency by setting inefficient prices that are inconsistent with the dispatch signals.

- 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 core functions is to identify actual or potential market design flaws.[1] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on mitigating market power in instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. FERC relies on effective market power mitigation when it approves market sellers to participate in the PJM market at market based rates.[2] In the PJM energy market, market power mitigation 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. FERC recognized these issues in its June 17, 2021 order.[4] Some units with market power have positive markups and some have inflexible parameters, which means that the cost-based offer was not used and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power. 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. 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 rules permitting cost-based offers in excess of $1,000 per MWh.

1 OATT Attachment M (PJM Market Monitoring Plan).

2 See *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040 (2019); *order on reh'g*, Order No. 861-A; 170 FERC ¶ 61,106 (2020).

3 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.

4 175 FERC ¶ 61,231 (2021).

Overview

Supply and Demand

Market Structure

- **Supply.** In the first nine months of 2023, 2,802 MW of new resources were added in the energy market, and 6,612 MW of resources were retired.

  The real-time hourly on peak average offered supply was 152,027 MW in the summer of 2022, and 150,271 MW in the summer of 2023. The day-ahead hourly on peak average offered supply was 161,651 MW in the summer of 2022, and 161,706 MW in the summer of 2023.

  The real-time hourly average cleared generation in the first nine months of 2023 decreased by 2.6 percent from the first nine months of 2022, from 96,397 MWh to 93,886 MWh.

  The day-ahead hourly average supply in the first nine months of 2023, including INCs and UTCs, increased by 8.3 percent from the first nine months of 2022 from 110,598 MWh to 119,823 MWh.

- **Demand.** The real-time hourly peak load plus exports in the first nine months of 2023 was 152,797 MWh (144,215 MWh of load plus 8,583 MWh of gross exports) in the HE 1800 (EPT) on July 27, 2023, which was 2.2 percent, 3,267 MWh, higher than the PJM peak load plus exports in the first nine months of 2022, which was 149,531 MWh in the HE 1800 (EPT) on July 20, 2022.

  The real-time hourly average load in the first nine months of 2023 decreased by 3.9 percent from the first nine months of 2022, from 90,514 MWh to 87,003 MWh.

  The day-ahead hourly average demand in the first nine months of 2023, including DECs and UTCs, increased by 8.2 percent from the first nine months of 2022, from 105,195 MWh to 113,807 MWh.

Market Behavior

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. The hourly average submitted increment offer MW increased by 14.8 percent and cleared increment MW increased by 21.3 percent in the first nine months of 2023 compared to the first nine months of 2022. The hourly average submitted decrement bid MW decreased by 10.3 percent and cleared decrement MW decreased by 5.7 percent in the first nine months of 2023 compared to the first nine months of 2022. The hourly average submitted up to congestion bid MW increased by 121.5 percent and cleared up to congestion bid MW increased by 104.4 percent in the first nine months of 2023 compared to the first nine months of 2022.

Market Performance[5]

- **Generation Fuel Mix.** In the first nine months of 2023, generation from coal units decreased 30.3 percent, generation from natural gas units increased 9.3 percent, and generation from oil increased 23.4 percent compared to the first nine months of 2022. Wind and solar output decreased by 1.1 percent compared to the first nine months of 2022, supplying 4.7 percent of PJM energy in the first nine months of 2023.
- **Fuel Diversity.** The fuel diversity of energy generation in the first nine months of 2023, measured by the fuel diversity index for energy (FDI_e), decreased 3.7 percent compared to the first nine months of 2022.
- **Marginal Resources.** In the PJM Real-Time Energy Market in the first nine months of 2023, coal units were 9.3 percent and natural gas units were 84.3 percent of marginal resources. In the first nine months of 2022, coal units were 10.7 percent and natural gas units were 74.3 percent of marginal resources.

5 The MMU uses the dispatch run marginal resource and sensitivity factor data, rather than the pricing run data, in the analysis of the day-ahead market for January 2022 through June 2023 because the PJM pricing run sensitivity factor data is not correct. Nonetheless, PJM uses LMPs generated in the pricing run as settlement LMPs.

In the first nine months of 2023, UTCs were 53.8 percent, INCs were 14.7 percent, DECs were 18.0 percent, and generation resources were 13.3 percent of marginal resources. In the first nine months of 2022, UTCs were 48.1 percent, INCs were 19.0 percent, DECs were 23.0 percent, and generation resources were 9.5 percent of marginal resources.

- **Prices.** The real-time load-weighted average LMP in the first nine months of 2023 decreased $46.97 per MWh, or 60.3 percent from the first nine months of 2022, from $77.84 per MWh to $30.87 per MWh. This is the largest dollar and percent decrease in PJM real-time load-weighted average LMP for the first three quarters of the year since PJM competitive markets were introduced in 1999.

  The day-ahead load-weighted average LMP in the first nine months of 2023 decreased $45.07, or 58.6 percent from the first nine months of 2022, from $76.97 per MWh to $31.90 per MWh. This is the largest dollar and percent decrease in PJM day-ahead load-weighted average LMP for the first three quarters of the year since competitive markets were introduced in 1999.

- **Fast Start Pricing.** The real-time load-weighted average PLMP was $30.87 per MWh for the first nine months of 2023, which is 5.9 percent, $1.73 per MWh, higher than the real-time load-weighted average DLMP of $29.14 per MWh. The day-ahead load-weighted average PLMP was $31.90 per MWh for the first nine months of 2023, which is 0.1 percent, $0.04 per MWh, higher than the day-ahead load-weighted average DLMP of $31.86 per MWh.

- **Components of Real-Time LMP.** In the PJM Real-Time Energy Market in the first nine months of 2023, 15.2 percent of the load-weighted LMP was the result of coal costs, 43.7 percent was the result of gas costs, 8.4 percent was the result of the cost of emission allowances, 4.6 percent was the result of transmission constraint violation penalty factors, and, 2.4 percent was the result of the commitment costs of fast start units.

- **Changes in Real-Time Prices.** Of the $46.97 per MWh decrease in the real-time load weighted average LMP, $30.57 per MWh (65.1 percent) was in the fuel and consumables cost components of LMP, $2.82 per MWh (6.0 percent) was in the emissions cost components of LMP, $5.70 per MWh (12.1 percent) was in the sum of the markup, maintenance, and ten percent adder components of LMP, $3.04 per MWh (6.5 percent) was in the transmission constraint penalty factor component of LMP, and $1.45 per MWh (3.1 percent) was in the scarcity component of LMP.

- **Components of Day-Ahead LMP.** In the PJM Day-Ahead Energy Market in the first nine months of 2023, 15.6 percent of the load-weighted LMP was the result of gas costs, 17.1 percent of the load-weighted LMP was the result of coal costs, 18.9 percent was the result of INCs, 26.0 percent was the result of DECs, 3.8 percent was the result of UTCs, and 8.2 percent was the result of positive markup.

- **Changes in Day-Ahead LMP.** Of the $44.95 per MWh decrease in the day-ahead load weighted average LMP, $26.73 per MWh (59.5 percent) was in the virtual and dispatchable transactions cost components of LMP, $11.24 per MWh (25.0 percent) was in the fuel and consumables cost components of LMP, $ 3.95per MWh (8.8 percent) was in the market power related components of LMP, $3.03 per MWh (6.7 percent) was in the sum of all the other components of LMP.

- **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 day-ahead and real-time average prices was -$0.81 per MWh in the first nine months of 2023, and $0.21 per MWh in the first nine months of 2022. The difference between day-ahead and real-time average prices, by itself, is not a measure of the competitiveness or effectiveness of the day-ahead energy market.

Scarcity

- There were 41 intervals with five minute shortage pricing on four days in the first nine months of 2023. These shortages did not correspond with any emergency warning or action.
- There were 2,475 five minute intervals, or 3.1 percent of all five minute intervals, in the first nine months of 2023 for which at least one RT SCED

solution showed a shortage of reserves, and 845 five minute intervals, or 1.1 percent of all five minute intervals, in the first nine months of 2023 for which more than one RT SCED solution showed a shortage of reserves. PJM triggered shortage pricing for 41 five minute intervals, or 0.05 percent of all five minute intervals.

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. Three suppliers were jointly pivotal in the day-ahead market on 155 days, 56.8 percent of the days, in the first nine months of 2023 and 215 days, 78.8 percent of the days, in the first nine months of 2022.
- **Local Market Power.** In the first nine months of 2023, in the real-time market, the 500 kV system, 10 zones, and PJM/MISO experienced congestion resulting from one or more constraints binding for 75 or more hours. For seven out of the top 10 congested facilities (by real-time binding hours) in the first nine months of 2023, the average number of suppliers providing constraint relief was three or fewer. There was a high level of concentration within the local markets for providing relief to the most congested facilities in the PJM Real-Time Energy Market. The local market structure was not competitive.

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 1.5 percent in the first nine months of 2022 to 1.8 percent in the first nine months of 2023. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased 1.5 percent in the first nine months of 2022 to 1.4 percent in the first nine months of 2023. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have had a significant impact on prices in the absence of local market power mitigation.

  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 increased from 0.06 percent in the first nine months of 2022 to 0.17 percent in the first nine months of 2023. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.15 percent in the first nine months of 2022 to 0.13 percent in the first nine months of 2023. The low offer cap percentages do not mean that units manually committed for reliability reasons do not have market power. All units manually committed for reliability have market power and all are treated as if they had market power. These units are not capped to their cost-based offers because they tend to offer with a negative markup in their price-based offers, particularly at the economic minimum level, which means that PJM's offer capping process results in the use of the price-based offer for commitment even if it has less flexible operating parameters.
- **Parameter Mitigation.** In the first nine months of 2023, 32.4 percent of unit hours for units that failed the TPS test in the day-ahead market were committed on price-based schedules that were less flexible than their cost-based schedules. On days when cold weather alerts and hot weather

alerts were declared, 52.5 percent of unit hours in the day-ahead energy market were committed on price-based schedules that were less flexible than their price PLS schedules.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** In the first nine months of 2023, no units qualified for an FMU adder. In 2022, no units qualified for an FMU adder. In 2021, one unit qualified for an FMU adder.
- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. While the average markup index in the real-time market was -0.03 in the first nine months of 2023, some marginal units did have substantial markups. The highest markup for any marginal unit in the real-time market in the first nine months of 2023 was more than $400 per MWh when using unadjusted cost-based offers.

  While the average markup index in the day-ahead market was 0.22 in the first six months of 2023, some marginal units did have substantial markups. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the day-ahead market in the first six months of 2023 was more than $100 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.

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 2023, the unadjusted markup component of LMP was $0.77 per MWh or 2.5 percent of the PJM load-weighted average LMP. July had the highest unadjusted peak markup component, $3.23 per MWh, or 6.7 percent of the real-time peak hour load-weighted average LMP for June.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In the first nine months of 2023, the unadjusted markup component of LMP was $2.62 per MWh or 8.2 percent of the PJM day-ahead load-weighted average LMP. July had the highest unadjusted peak markup component, $4.00 per MWh, or 9.0 percent of the day-ahead peak hour load-weighted average LMP.[6]

  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.
- **Markup and Local Market Power.** Comparison of the markup behavior of marginal units with TPS test results shows that for 4.2 percent of all real-time marginal unit intervals in the first nine months of 2023, the marginal unit had both local market power as determined by the TPS test and a positive markup. The fact that units with market power had a positive markup means that the cost-based offer was not used, that a higher price-based offer was used, and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power.
- **Markup and Aggregate Market Power.** In the first nine months of 2023, pivotal suppliers in the aggregate market, committed in the day-ahead market and identified as one of three day-ahead aggregate pivotal suppliers, set real-time market prices with markups over $100 per MWh on 61 days.

6 The MMU uses the dispatch run marginal resource and sensitivity factor data, rather than the pricing run data, in the analysis of the day-ahead market for January 2022 through September 2023 because the PJM pricing run sensitivity factor data is not correct. Nonetheless, PJM uses LMPs generated in the pricing run as settlement LMPs.

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 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.)

Fuel Cost Policies

- 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 temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy. (Priority: Low. First reported 2020. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy. (Priority: Medium. First reported 2020. Status: Not adopted.)

Cost-Based Offers

- The MMU recommends that Manual 15 (Cost Development Guidelines) be replaced or updated with a straightforward description of the components of cost-based offers and the mathematically correct calculation of cost-based offers. (Priority: Medium. First reported 2016. Status: Partially adopted Q1 2022.)[7]
- 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: Adopted 2022.)
- The MMU recommends the removal of all maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics. (Priority: Medium. First reported 2020. Status: Adopted 2023.)
- The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of the operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Partially Adopted.)
- The MMU recommends that soak costs, soak time and the MWh produced during soaking be modeled separately. This will ensure that the time required for units to reach a dispatchable level is known and used in the unit commitment process instead of only being communicated verbally

7 Manual 15 has been updated with the correct calculations and descriptions of the cost components for incremental energy offers and no load costs. The start cost calculations have not been approved.

between dispatchers and generators. Separating soak costs from start costs and modeling the MWh produced during soaking allows for a better representation of the costs because it eliminates the need to simply assume the price paid for those MWh. (Priority: Medium. First reported 2022. 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.)

Market Power: TPS Test and Offer Capping

- 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.)[8]
- The MMU recommends that PJM modify the process of applying the TPS test in the day-ahead energy market to ensure that all local markets created by binding constraints are tested for market power and to ensure that market sellers with market power are appropriately mitigated to their competitive offers. (Priority: High. First reported Q1 2022. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times. (Priority: High. First reported Q3 2021. Status: Not adopted.)
- The MMU recommends, if the preferred recommendation is not implemented, that in order to ensure effective market power mitigation, PJM always enforce parameter limited values when the TPS test is failed and during high load conditions such as cold and hot weather alerts and emergency conditions. (Priority: High. First reported 2015. Status: Not 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 consistently positive or negative across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999, 2017.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)[9]

Offer Behavior

- The MMU recommends that resources not be allowed to violate the ICAP must offer requirement. The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without

8 The real-time market formula for determining the lowest cost schedule is currently documented.

9 The applicability of the FMU and AU adders is limited by the rule implemented in 2014 requiring that net revenues must fall below avoidable costs, but the possibility of FMU and AU adders is still part of the PJM Market Rules.

an outage that reflects the derate. (Priority: Medium. First reported 2020. Status: Not adopted.)

- The MMU recommends that storage and intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM integrate all the outage reporting tools in order to enforce the ICAP must offer requirement, ensure that outages are reported correctly and eliminate reporting inconsistencies. Generators currently submit availability in three different tools that are not integrated, Markets Gateway, eDART and eGADS. (Priority: Medium. First reported 2022. Status: Not adopted.)
- The MMU recommends that gas generators be required to check with pipelines throughout the operating day to confirm that nominations are accepted beyond the NAESB deadlines, and that gas generators be required to place their units on forced outage until the time that pipelines allow nominations to consume gas at a unit. (Priority: Medium. First reported Q1 2022. Status: Not adopted.)

Capacity Resources

- The MMU recommends that capacity resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity market design. 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 resource performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)[10]
- 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 resources. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits. (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 enforced at the time, or are based on inferior transportation service procured by the generator. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM require generators that violate their approved turn down ratio (by either using the fixed gen option or increasing their economic minimum) to use the temporary parameter exception process that requires market sellers to demonstrate that the request is based on a physical and actual constraint. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends: that gas generators be required to confirm, regularly during the operating day, that they can obtain gas if requested to operate at their economic maximum level; that gas generators provide that information to PJM during the operating day; and that gas generators be required to be on forced outage if they cannot obtain gas during the operating day to meet their must offer requirement as a result of pipeline restrictions, and they do not have backup fuel. As part of this, the MMU recommends that PJM collect data on each individual generator's fuel

10 Flexible parameter standards are in place for combined cycle and combustion turbine resources when operating on a parameter limited schedule, but not for other schedules or generating technologies.

supply arrangements at least annually or when such arrangements change, and analyze the associated locational and regional risks to reliability. (Priority: Medium. First reported Q1 2022. Status: Not adopted.)

- The MMU recommends, if the capacity market seller offer cap were to be calculated using the historical average balancing ratio, that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs), and only include those events that trigger emergencies at a defined zonal or higher level. (Priority: Medium. First reported 2018. 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 and when the transmission penalty factors will be used to set the shadow price. The MMU recommends that PJM end the practice of discretionary reductions in transmission line ratings modeled in the market clearing and included in LMP. (Priority: Medium. First reported 2015. Status: Partially adopted 2020.)[11]
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use closed loop interface or surrogate constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013.[12] (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.[13] [14] (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.)
- 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

11 PJM created a more transparent process for transmission constraint penalty factors and added it to the tariff in 2020. Policies on line rating reductions (including limit control percentage) and the duration of violations remain discretionary and undocumented in the PJM Market Rules.

12 This recommendation was the result of load shed events in September, 2013. For detailed discussion, please see *2013 Annual State of the Market Report for PJM*, Volume II, Section 3 at 114 – 116.

13 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.

14 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 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 coordination 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, including soak time for units with a steam turbine, configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM stop capping the system marginal price in RT SCED and instead limit the sum of violated reserve constraint shadow prices used in LPC to $1,700 per MWh. (Priority: Medium. First reported Q1, 2021. Status: Not adopted.)
- The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirement for synchronized and primary reserves by the amount of the reserves deployed. (Priority: Medium. First reported 2021. Status: Not adopted.)

Transparency

- The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM manuals, including defining all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule availability on an hourly basis. (Priority: Medium. First reported 2015. Status: Partially adopted.)[15]
- The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases, that are used to send dispatch signals to resources, and for pricing, to minimize discretion. (Priority: High. First reported 2018. Status: Partially adopted.)[16]

Virtual Bids and Offers

- The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues. (Priority: Medium. First reported 2020. 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 2023, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, markup, marginal units, participation in demand response programs, virtual bids and offers, loads and prices.

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. In a competitive market, prices are directly related to input prices, the marginal cost to serve load. In the first nine months of 2023, LMP decreased by $46.97 per MWh compared to the first nine months of 2022. The largest contributor to decreased prices was the cost of fuel, primarily natural gas and

15 Fuel type is reported by offer schedule, but it can be inaccurate on an hourly basis.

16 The PJM Market Rules clarify that shortage case approval will be based on RT SCED, but does not address RT SCED case choice or load bias.

coal. The fuel cost components of LMP (the sum of gas, coal, oil, landfill gas, and consumables) decreased $30.57 per MWh, 65.1 percent of the decrease in LMP. The emissions cost components of LMP decreased by $2.82 per MWh, 6.0 percent of the decrease in LMP. The transmission constraint penalty factor component decreased by $3.04 per MWh, 6.5 percent of the decrease in LMP.

The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in the first nine months of 2023 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high demand periods represents economic withholding. Economic withholding occurs when generator offers are greater than competitive levels. In the first nine months of 2023, the markup, ten percent adder, and maintenance cost components, together decreased by $5.70 per MWh or 12.1 percent of the decrease in LMP.

The potential for prolonged and excessively high administrative pricing in the energy market due to reserve penalty factors and transmission constraint penalty factors remains an issue that needs to be addressed.[17] There also continue to be significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on accurately estimated reserve levels. For example, in July, August, and September of 2022, PJM approved a shortage case for one RT SCED five minute interval out of 673 intervals with multiple shortage solutions, while the same months in 2021 had only 404 intervals with multiple shortage solutions and nine approved shortage intervals. During Elliott, PJM approved 45.4 percent of SCED shortage solutions. The pattern of shortage case approvals indicates that PJM considers factors other than RT SCED producing a shortage case when deciding whether to approve shortage cases.

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 and ensure no scarcity pricing when such pricing is not consistent with market conditions. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy, as in PJM's 2019 ORDC proposal, is not required in PJM, even under the market transition to a fleet with more renewable resources. 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, that scarcity pricing not be excessive or punitive, and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets.

The PJM defined inputs to the dispatch tools, particularly the RT SCED, have substantial effects on energy market outcomes. Transmission line ratings, transmission penalty factors, load forecast bias, and hydro resource schedules change the dispatch of the system, affect prices, and can create significant price increases, particularly through transmission line limit violations. PJM operator interventions to reduce line ratings unnecessarily trigger transmission constraint penalty factors and significantly increase prices. Violations of the artificially reduced line limits had a direct effect on higher LMP in the first nine months of 2023. If the line limits had not been artificially reduced for the PJM transmission constraints and everything else remained unchanged, fewer constraints would have been violated and the transmission penalty factor's contribution to the load weighted average LMP in the first nine months of 2023 would have decreased by 99.2 percent from $1.42 to $0.01 per MWh. PJM should evaluate its interventions in the market, consider whether the interventions are appropriate, and provide greater transparency to enhance market efficiency.

Fast start pricing, implemented on September 1, 2021, has disconnected pricing from dispatch instructions and created a greater reliance on uplift rather than price as an incentive to follow PJM's instructions. The objective

17 177 FERC ¶ 61,209 (2021).

of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs using fast start pricing prioritizes minimizing uplift over minimizing production costs.[18] The tradeoff exists 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. Units that start in one hour are not actually 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 is paying new forms of uplift in an attempt to counter the distorted incentives inherent in fast start pricing. PJM is also using the pricing run to implement other differences from the dispatch run that are not related to fast start pricing, including differences in transmission constraint penalty factors and system marginal price capping. Every difference between the dispatch run and the pricing run introduces another inefficiency in the market. In the two years since fast start pricing was introduced, the market has not responded with new entry of fast start units despite consistently higher LMP when a fast start unit sets price.

PJM's arguments for changing energy market price formation asserted that fast start pricing and the extended ORDC would price flexibility in the market, but instead they benefit inflexible units. The fast start pricing and extended ORDC solutions 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? Are units inflexible because the PJM software does not model combined cycle transitions? The question of how to provide market incentives for investment in flexible units, for investment in increased flexibility of existing units, and for operating at the full extent of existing flexibility 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.

The relationship between supply and demand, regardless of the specific market, along with market concentration and the extent of pivotal suppliers, is referred to as the supply-demand fundamentals or economic fundamentals or market structure. 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. Even a low HHI may be consistent with the exercise of market power with a low price elasticity of demand. 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.[19] 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. The Commission

18 See 173 FERC ¶ 61,244 (2020).

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

recognized some of these issues in its order issued on June 17, 2021.[20] PJM continues to ignore the evidence cited by the Commission and denies the prevalence of these issues, instead of ensuring that market power mitigation works as intended and results in efficient market outcomes.[21] Many of these issues can be resolved by simple rule changes. The MMU proposed these rule changes in its response submitted on October 15, 2021, and in the stakeholder process.[22] [23] The MMU recommendations would shorten the solution time of the day-ahead market software, which would help facilitate enhanced combined cycle modelling. PJM's primary proposal would weaken market power mitigation as part of implementing the enhanced combined cycle modelling project, although PJM has failed to explain why such weakening makes sense. PJM's proposals would ensure that the identified issues with the implementation of market power mitigation in the energy market would never be addressed and would be exacerbated. PJM should endorse only solutions that ensure that market power mitigation is protected.

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 all costs that are related to electric production are short run marginal costs, 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. This rule also had unintended consequences for market seller offer caps in the capacity market. Maintenance costs includable in energy offers cannot be included in capacity market offer caps based on avoidable costs. As a result, capacity market offer caps based on net avoidable costs were lower than they would have been if maintenance costs had been correctly included in avoidable costs rather than incorrectly defined to be part of short marginal costs of producing energy and includable in energy offers.

A competitive market requires that prices increase when fuel costs increase and that prices decrease when fuel costs decrease. A competitive market does not require that prices increase when markup increases or when PJM artificially triggers transmission constraint penalty factors. 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 2023 or prior years. Given the structure of the energy market which can permit the exercise of aggregate and local 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 and correcting the offer capping process for resources with local market power. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2023.

20 See 175 FERC ¶ 61,231 (2021).
21 *See* PJM. "Answer of PJM Interconnection L.L.C.," Docket No. EL21-78 (September 15, 2021).
22 *See* "Comments of the Independent Market Monitor for PJM," Docket No. EL21-78 (October 15, 2021).
23 *See* "Schedule Selection Proposal," MMU presentation to the Markets and Reliability Committee (October 25, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MRC_Schedule_Selection_20231025.pdf>; "Schedule Selection: IMM Package," MMU Presentation to the Market Implementation Committee (September 6, 2023), >https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Schedule_Selection_IMM_Package_20230906.pdf>; "Schedule Selection: IMM Proposal," MMU Presentation to the Market Implementation Committee (August 9, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Schedule_Selection_IMM_Proposal_20230809.pdf>; "Least Cost Schedule Analysis," MMU Presentation at the MIC Special Session (July 17, 2023), https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Special_Session_Least_Cost_Schedule_Analysis_20230717.pdf; "Multischedule Model and Mitigation: IMM Package," MMU Presentation to the MIC Special Session (May 24, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Multischedule_Model_and_Mitigation_IMM_Package_20230524.pdf>; "Education: Schedule Selection and Market Power Mitigation," MMU Presentation to the MIC Special Session (March 29, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Special_Session_Education_Schedule_%20Selection_and_Market_Power_Mitigation_20230330.pdf>; "Offer Schedule Selection," MMU Presentation to the Market Implementation Committee (February 8 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Offer_Schedule_Selection_20230208.pdf>.

Supply and Demand

Market Structure

Supply

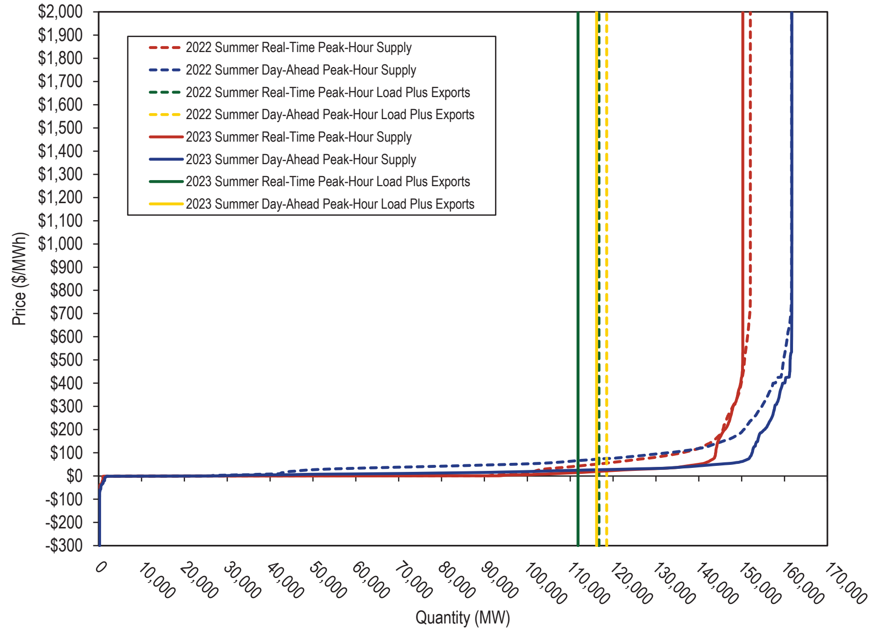
Supply includes physical generation, imports and virtual transactions.

In the first nine months of 2023, 2,802 MW of new physical generation resources were added in the energy market, and 6,612 MW of resources were retired.

Figure 3-1 shows real-time and day-ahead hourly supply curves in the summer of 2022 and 2023.[24] [25] The real-time supply curve includes hourly on peak average offers. The real-time supply curve only includes available MW from units that are online or have a notification plus start time that is no more than one hour. The day-ahead supply curve shows all available hourly on peak average offers.

The real-time hourly on peak average offered supply was 152,027 MW in the summer of 2022, and 150,271 MW in the summer of 2023. The day-ahead hourly on peak average offered supply was 161,651 MW in the summer of 2022, and 161,706 MW in the summer of 2023.

Figure 3-1 Real-time and day-ahead hourly supply curves: summer of 2022 and 2023



24 Real-time supply includes real-time generation offers and import MWh.
25 The supply curve period is from June 1 to August 31.

Figure 3-2 shows the typical dispatch range.

Figure 3-2 Typical dispatch range of supply curves

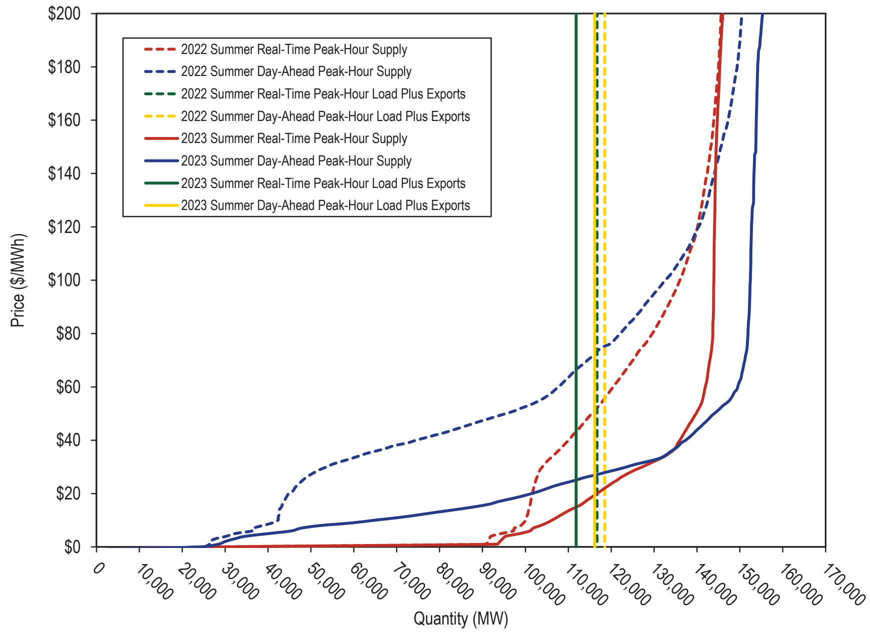


Table 3-2 shows the price elasticity of the real-time supply curve for the peak hours in the summer of 2022 and 2023 by load level.

The price elasticity of the supply curve measures the responsiveness of the quantity supplied (GW) to a change in price:

$$\text{Elasticity of Supply} = \frac{\text{Percent change in quantity supplied}}{\text{Percent change in price}}$$

The supply curve is defined to be elastic when elasticity is greater than 1.0. The quantity supplied is more sensitive to changes in price the higher the elasticity. Although the aggregate supply curve may appear flat as a result of the wide range in prices and quantities, the calculated elasticity is inelastic throughout.

Table 3-2 Price elasticity of the supply curve

	GW			
Summer	Min - 95	95 - 115	115 - 135	135 - Max
2019	0.020	0.302	0.415	0.003
2020	0.026	0.256	0.353	0.003
2021	0.017	0.104	0.286	0.005
2022	0.014	0.027	0.178	0.013
2023	0.015	0.061	0.162	0.004

Real-Time Supply

The real-time hourly average cleared generation in the first nine months of 2023 decreased by 2.6 percent from the first nine months of 2022, from 96,397 MWh to 93,886 MWh.[26]

The real-time hourly average cleared supply including imports in the first nine months of 2023 decreased by 2.7 percent from the first nine months of 2022, from 98,064 MWh to 95,437 MWh.

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

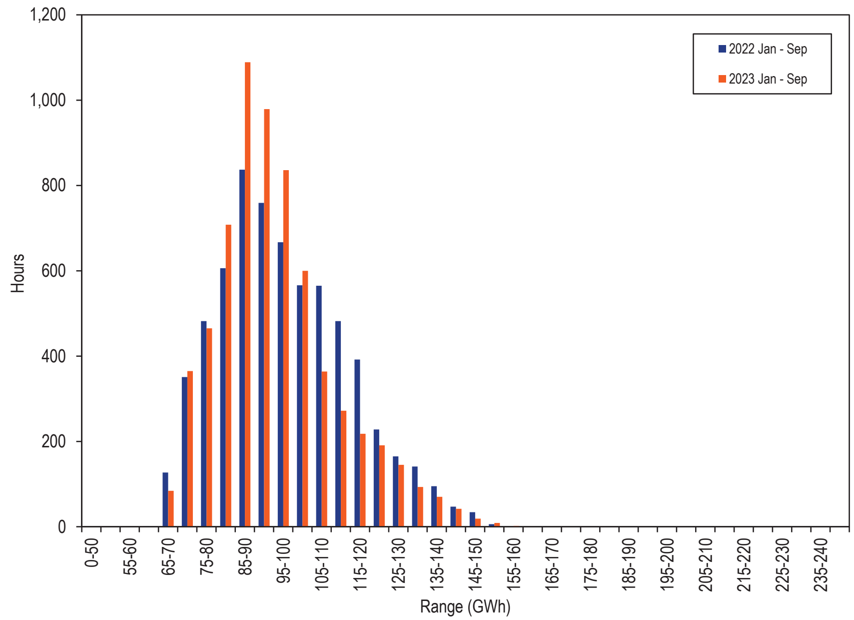
- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MW, as a price taker, from a unit that may also have a dispatchable component above the fixed MW.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MW and corresponding offer prices from a specific unit.
- **Import.**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

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

PJM Real-Time Supply Frequency

Figure 3-3 shows the hourly distribution of the real-time generation plus imports for the first nine months of 2022 and 2023.

Figure 3-3 Distribution of real-time generation plus imports: January through September, 2022 and 2023[27]



PJM Real-Time Average Cleared Supply

Table 3-3 shows the real-time hourly average cleared supply and its standard deviation for the first nine months of 2001 through 2023. The real-time hourly average cleared generation in the first nine months of 2023 decreased by 2.6 percent from the first nine months of 2022, from 96,397 MWh to 93,886 MWh.

Table 3-3 Real-time hourly average generation and generation plus imports: January through September, 2001 through 2023

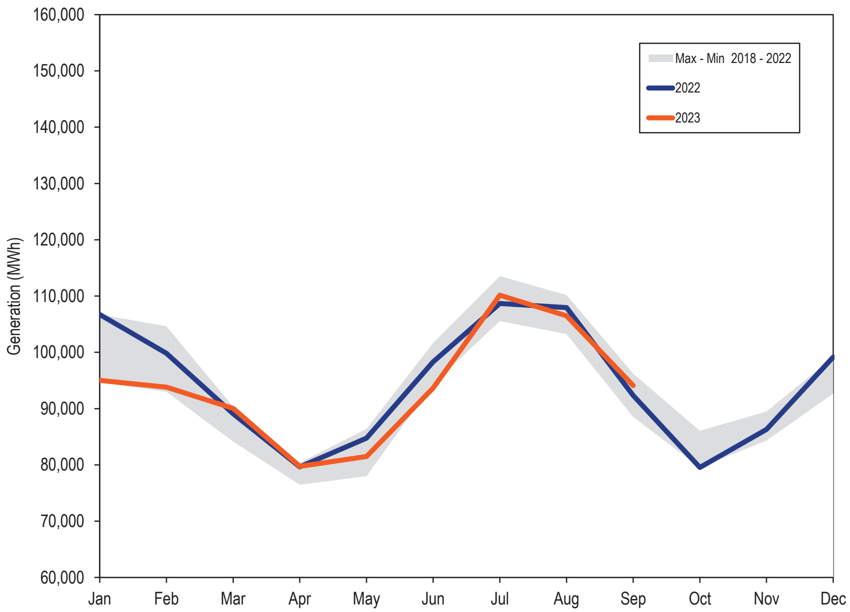
	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
Jan-Sep	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2001	30,304	5,216	33,299	5,571	NA	NA	NA	NA
2002	34,467	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%)
2020	92,226	17,790	92,983	17,883	(3.5%)	3.4%	(3.8%)	2.9%
2021	95,792	18,039	96,519	18,173	3.9%	1.4%	3.8%	1.6%
2022	96,397	16,816	98,064	17,031	0.6%	(6.8%)	1.6%	(6.3%)
2023	93,886	15,544	95,437	15,561	(2.6%)	(7.6%)	(2.7%)	(8.6%)

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

PJM Real-Time Monthly Average Generation

Figure 3-4 compares the real-time monthly average generation in 2022 and the first nine months of 2023 with the historic five year range.

Figure 3-4 Real-time monthly average generation: 2022 through September 2023



Day-Ahead Cleared Supply

The day-ahead hourly average supply in the first nine months of 2023, including INCs and UTCs, increased by 8.3 percent from the first nine months of 2022 from 110,598 MWh to 119,823 MWh.

The day-ahead hourly average supply in the first nine months of 2023, including INCs, UTCs and imports, increased by 8.4 percent from the first nine months of 2022, from 110,875 MWh to 120,158 MWh.

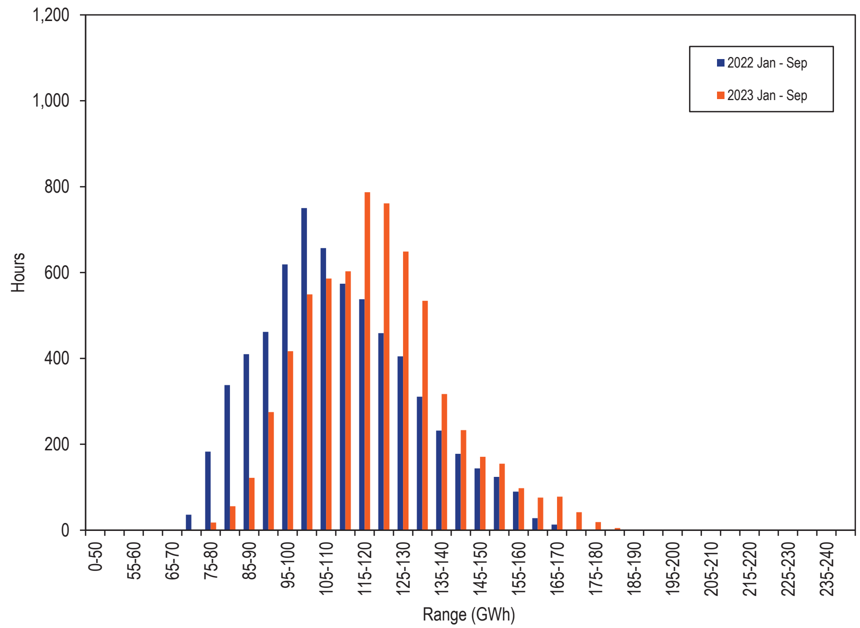
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **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 3-5 shows the distribution of the day-ahead hourly cleared supply, including increment offers, up to congestion transactions, and imports for the first nine months of 2022 and 2023.

Figure 3-5 Distribution of day-ahead cleared supply plus imports: January through September, 2022 and 2023[28]



PJM Day-Ahead Average Supply

Table 3-4 presents day-ahead hourly cleared supply summary statistics for each year from the first nine months of 2001 through 2023. The day-ahead hourly average supply in the first nine months of 2023, including INCs and UTCs, increased by 8.3 percent from the first nine months of 2022 from 110,598 MWh to 119,823 MWh.

Table 3-4 Day-ahead hourly average cleared supply and cleared supply plus imports: January through September, 2001 through 2023

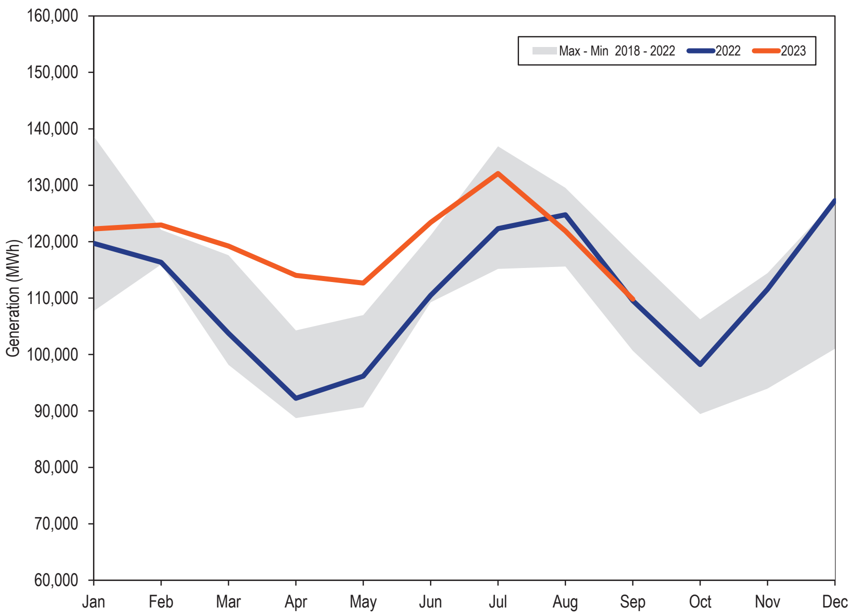
	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
Jan-Sep	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2001	27,519	4,839	28,279	4,911	NA	NA	NA	NA
2002	30,080	10,982	30,629	10,992	9.3%	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%)
2020	115,205	20,611	115,386	20,577	(3.1%)	3.0%	(3.2%)	2.9%
2021	104,785	20,136	104,970	20,154	(9.0%)	(2.3%)	(9.0%)	(2.1%)
2022	110,598	19,369	110,875	19,455	5.5%	(3.8%)	5.6%	(3.5%)
2023	119,823	18,378	120,158	18,427	8.3%	(5.1%)	8.4%	(5.3%)

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

PJM Day-Ahead Monthly Average Cleared Supply

Figure 3-6 compares the day-ahead monthly average cleared supply including increment offers and up to congestion transactions for 2022 and the first nine months of 2023 with the historic five year range. The monthly average day-ahead supply from February to June of 2023 was higher than the maximum of the past five years, primarily as a result of increased UTC volumes.

Figure 3-6 Day-ahead monthly average cleared supply: 2022 through September 2023



Real-Time and Day-Ahead Supply

Table 3-5 presents summary statistics for day-ahead and real-time cleared supply for the first nine months of 2022 and 2023. The last two columns of Table 3-5 are the day-ahead cleared supply minus the real-time cleared supply. The first column is the total physical day-ahead generation less the total physical real-time generation and the second column is the total day-ahead cleared supply less the total real-time cleared supply.

The total physical day-ahead average generation less the total physical real-time average generation in the first nine months of 2023 decreased 374 MWh from the first nine months of 2022, from -166 MWh to -541 MWh. The total day-ahead average supply less the total real-time average supply in the first nine months of 2023 increased 11,910 MWh from the first nine months of 2022, from 12,811 MWh to 24,721 MWh, primarily as a result of the increase in UTCs.

Table 3-5 Day-ahead and real-time hourly cleared supply (MWh): January through September, 2022 and 2023

		Day-Ahead					Real-Time		Day-Ahead Less Real-Time	
	Jan-Sep	Generation	INC Offers	Up to Congestion	Imports	Total Supply	Generation	Total Supply	Generation	Supply
Average	2022	96,231	3,463	10,904	277	110,875	96,397	98,064	(166)	12,811
	2023	93,345	4,185	22,292	335	120,158	93,886	95,437	(541)	24,721
Median	2022	93,568	3,393	10,221	226	108,409	94,370	95,821	(802)	12,589
	2023	90,457	4,043	22,583	251	119,053	91,427	92,887	(970)	26,165
Standard Deviation	2022	17,739	1,058	3,921	246	19,455	16,816	17,031	923	2,424
	2023	16,598	1,481	8,217	311	18,427	15,544	15,561	1,054	2,866
Peak Average	2022	104,740	3,797	11,866	325	120,728	104,383	106,177	357	14,552
	2023	101,224	4,931	24,383	372	130,910	101,247	102,962	(23)	27,948
Peak Median	2022	103,260	3,731	11,298	282	118,704	102,725	104,461	535	14,244
	2023	97,236	4,826	24,480	296	128,317	97,726	99,439	(490)	28,878
Peak Standard Deviation	2022	16,413	1,029	3,836	261	17,668	15,736	15,910	677	1,759
	2023	16,092	1,434	7,841	335	15,554	15,009	14,916	1,083	638
Off-Peak Average	2022	88,717	3,167	10,055	234	102,173	89,346	90,900	(628)	11,273
	2023	86,456	3,533	20,465	303	110,757	87,449	88,857	(993)	21,900
Off-Peak Median	2022	86,626	3,084	9,308	178	100,478	87,834	89,018	(1,207)	11,461
	2023	84,469	3,387	20,837	215	108,692	85,951	87,224	(1,482)	21,468
Off-Peak Standard Deviation	2022	15,307	993	3,797	222	16,603	14,416	14,604	891	1,999
	2023	13,720	1,184	8,102	284	15,347	12,928	12,907	793	2,440

Figure 3-7 shows the average cleared volumes of day-ahead and real-time supply by hour of the day in the first nine months of 2023. The day-ahead cleared supply consists of cleared MW of physical generation, imports, increment offers and up to congestion transactions. The real-time cleared supply consists of cleared MW of physical generation and imports.

Figure 3-7 Day-ahead and real-time cleared supply (Average volumes by hour of the day): January through September, 2023

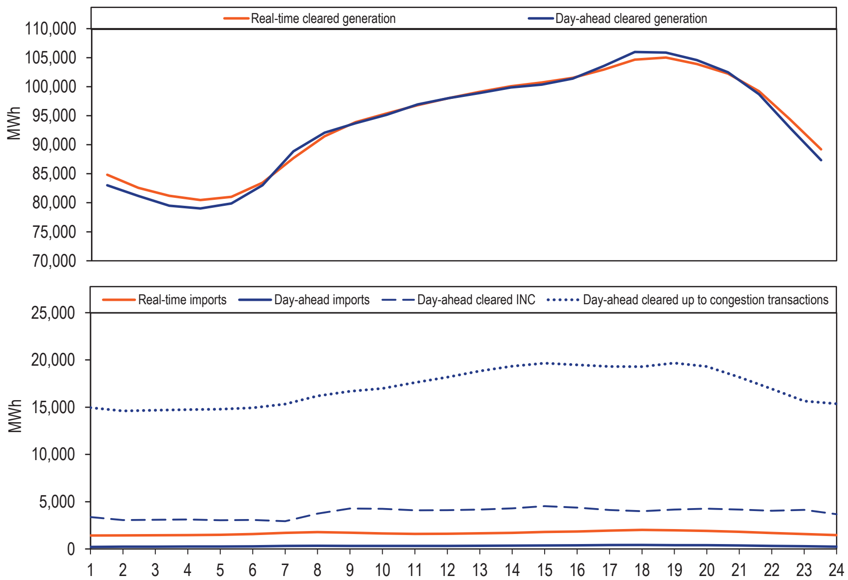
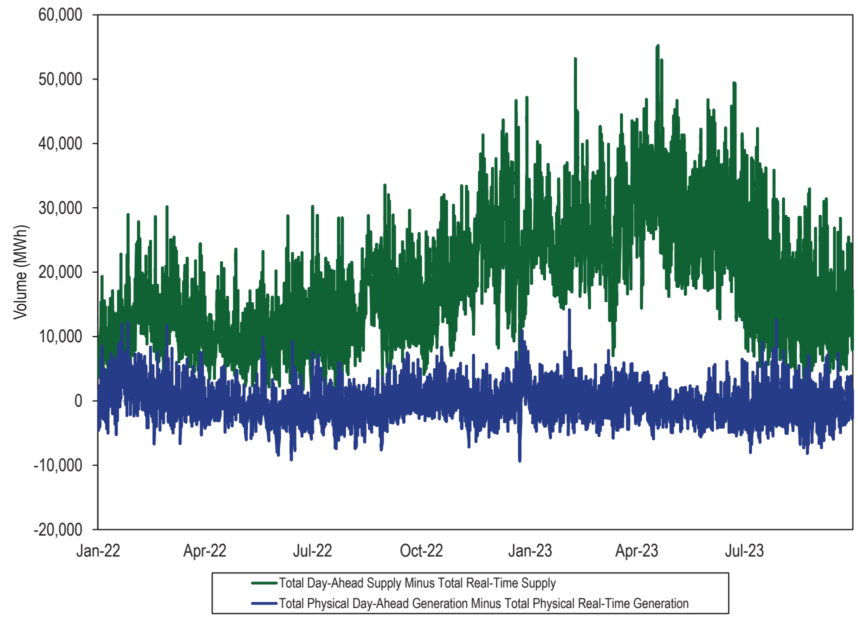


Figure 3-8 shows the difference between day-ahead and real-time daily average cleared supply in 2022 and the first nine months of 2023.

Figure 3-8 Difference between day-ahead and real-time daily average cleared supply: 2022 through September 2023



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, includes virtual transactions.[29]

Table 3-6 shows the peak load plus exports for the first nine months of 2009 through 2023.

The real-time hourly peak load plus exports in the first nine months of 2023 was 152,797 MWh (144,215 MWh of load plus 8,583 MWh of gross exports) in the HE 1800 (EPT) on July 27, 2023, which was 2.2 percent, 3,267 MWh, higher than the PJM peak load plus exports in the first nine months of 2022, which was 149,531 MWh in the HE 1800 (EPT) on July 20, 2022.

Table 3-6 Actual footprint peak load plus export: January through September, 2009 through 2023[30 31]

(Jan - Sep)	Date	Hour Ending (EPT)	PJM Load Plus Export (MWh)	Annual Change (MWh)	Annual Change (%)
2009	Mon, August 10	16	135,923	NA	NA
2010	Wed, July 07	17	149,376	13,453	9.9%
2011	Thu, July 21	17	169,290	19,915	13.3%
2012	Tue, July 17	18	166,081	(3,210)	(1.9%)
2013	Thu, July 18	17	157,277	(8,804)	(5.3%)
2014	Tue, June 17	18	142,428	(14,850)	(9.4%)
2015	Fri, February 20	8	144,850	2,422	1.7%
2016	Thu, August 11	17	154,743	9,893	6.8%
2017	Thu, July 20	16	148,343	(6,400)	(4.1%)
2018	Tue, August 28	17	152,509	4,166	2.8%
2019	Fri, July 19	18	153,589	1,080	0.7%
2020	Mon, July 20	18	148,996	(4,593)	(3.0%)
2021	Tue, August 24	18	151,680	2,684	1.8%
2022	Wed, July 20	18	149,531	(2,150)	(1.4%)
2023	Thu, July 27	18	152,797	3,267	2.2%

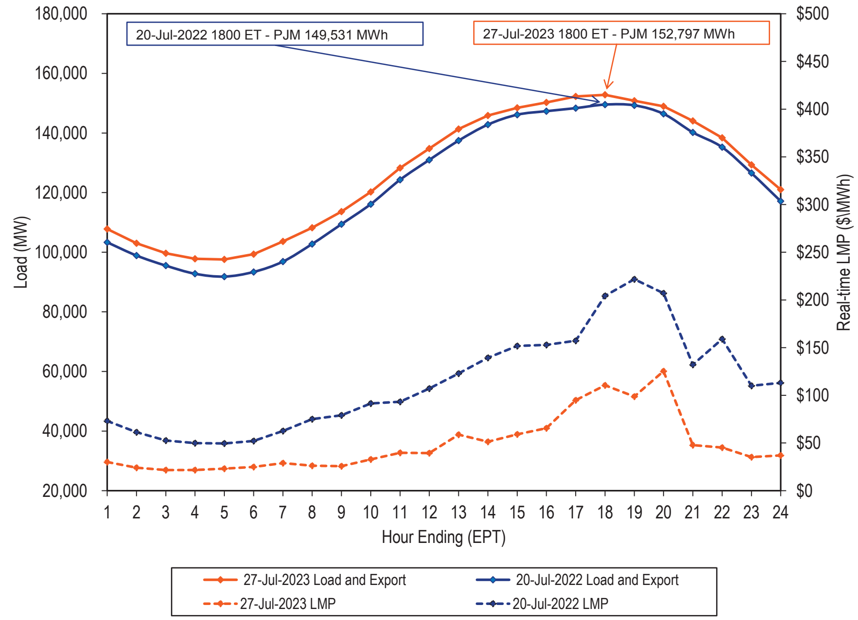
29 PJM reports peak load including accounting load plus an addback equal to PJM's estimated load drop from demand side resources. This will generally result in PJM reporting peak load values greater than accounting load values. PJM's load drop estimate is based on PJM Manual 19: Load Forecasting and Analysis," Attachment A: Load Drop Estimate Guidelines.

30 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>.

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

Figure 3-9 compares prices and demand on the peak load days for the first nine months of 2022 and 2023. The real-time average LMP for the July 20, 2022, peak load hour was $204.29 per MWh, and for the July 27, 2023, peak load hour it was $110.52 per MWh.

Figure 3-9 Peak load and export day comparison



Real-Time Demand

The real-time hourly average load in the first nine months of 2023 decreased by 3.9 percent from the first nine months of 2022, from 90,514 MWh to 87,003 MWh.[32]

The real-time hourly average demand including exports in the first nine months of 2023 decreased by 2.9 percent from the first nine months of 2022, from 96,196 MWh to 93,443 MWh.

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

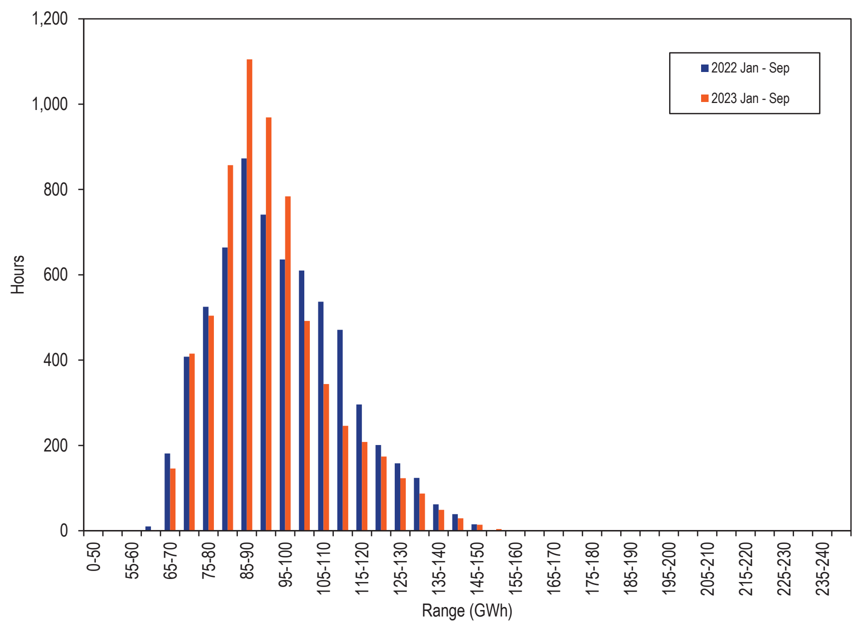
In the PJM Real-Time Energy Market, there are two types of demand:

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

PJM Real-Time Demand Duration

Figure 3-10 shows the distribution of the real-time hourly load plus exports for the first nine months of 2022 and 2023.[33]

Figure 3-10 Distribution of real-time load plus exports: January through September, 2022 and 2023[34]



33 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>.

34 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 2001 through 2023.[35] The real-time hourly average load in the first nine months of 2023 decreased by 3.9 percent from the first nine months of 2022, from 90,514 MWh to 87,003 MWh.

Table 3-7 Real-time hourly average load and load plus exports: January through September, 2001 through 2023

	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%)
2020	85,886	17,201	91,356	17,464	(4.4%)	2.4%	(3.8%)	3.2%
2021	89,515	16,875	94,746	17,748	4.2%	(1.9%)	3.7%	1.6%
2022	90,514	16,367	96,196	16,581	1.1%	(3.0%)	1.5%	(6.6%)
2023	87,003	15,308	93,443	15,633	(3.9%)	(6.5%)	(2.9%)	(5.7%)

PJM Real-Time Monthly Average Load

Figure 3-11 compares the real-time monthly average load plus exports in the first nine months of 2022 and 2023, with the historic five year range. In January, February, June and August of 2023, the monthly average load plus

35 Accounting load is used because accounting load is the load customers pay for in PJM settlements. 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. 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 the incorporation of marginal loss pricing in LMP.

exports was lower than the minimum of the past five years, primarily as a result of mild weather.

Figure 3-11 Real-time monthly average hourly load plus exports: 2022 through September 2023

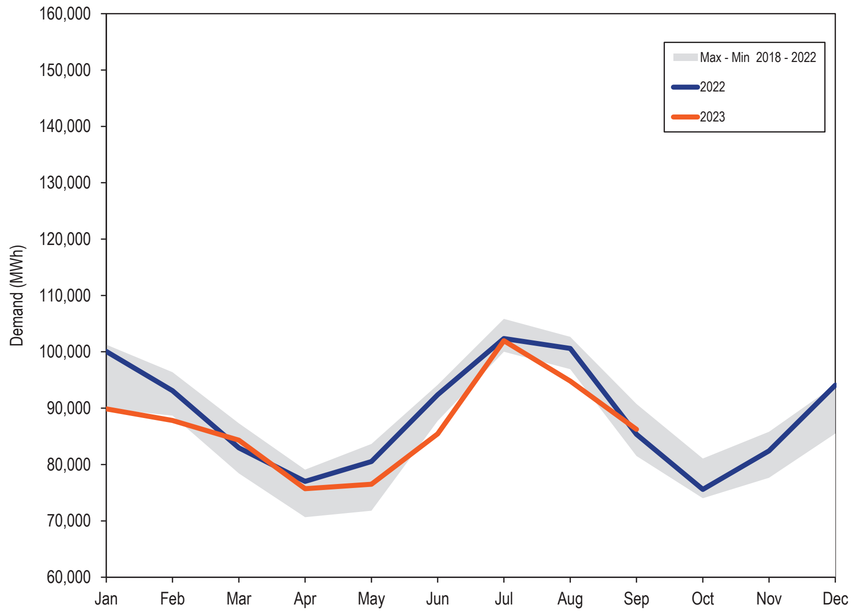
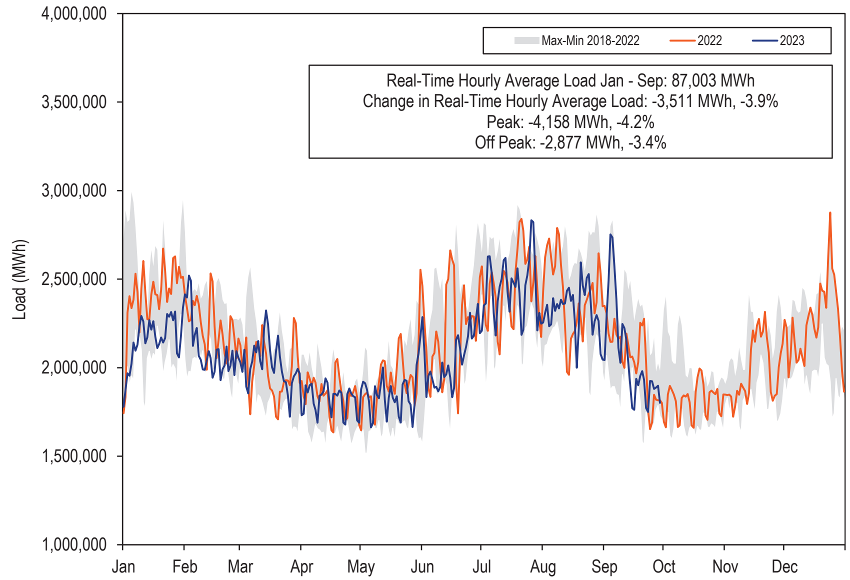


Figure 3-12 compares the real-time daily average load for 2022 and first nine months of 2023, with the historic five year range.

Figure 3-12 Real-time daily load: 2022 through September 2023



The real-time load is significantly affected by weather conditions. Table 3-8 compares the monthly heating and cooling degree days in the first nine months of 2022 and 2023.[36]

Heating degree days decreased 22.7 percent compared to the first nine months of 2022. Cooling degree days decreased 17.2 percent compared to the first nine months of 2022.

36 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings). PJM uses 60 degrees F for a heating degree day as stated in Manual 19.
Heating and cooling degree days are calculated by weighting the temperature at each weather station in the individual transmission zones using weights provided by PJM in Manual 19. Then the temperature is weighted by the real-time zonal accounting load for each transmission zone. After calculating an average hourly temperature across PJM, the heating and cooling degree formulas are used to calculate the daily heating and cooling degree days, which are summed for monthly reporting. The weather stations that provided the basis for the analysis are ABE, ACY, AVP, BWI, CAK, CLE, CMH, CRW, CVG, DAY, DCA, ERI, EWR, FWA, IAD, ILG, IPT, LEX, ORD, ORF, PHL, PIT, RIC, ROA, TOL and WAL.

Table 3-8 Heating and cooling degree days: 2022 through September 2023

	2022		2023		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	983	0	623	0	(36.6%)	0.0%
Feb	693	0	521	0	(24.8%)	0.0%
Mar	445	0	510	0	14.5%	0.0%
Apr	256	5	164	17	(35.9%)	261.1%
May	21	101	47	31	121.6%	(69.2%)
Jun	0	260	0	162	0.0%	(37.7%)
Jul	0	406	0	388	0.0%	(4.5%)
Aug	0	345	0	310	0.0%	(10.3%)
Sep	15	153	0	144	(100.0%)	(5.7%)
Oct	164	0				
Nov	386	3				
Dec	752	0				
Jan-Sep	2,413	1,270	1,865	1,052	(22.7%)	(17.2%)

Figure 3-13 shows the real-time daily load and the weather normalized load in 2022 and the first nine months of 2023.

Weather normalized load is calculated using the historic relationship between the daily load and HDD, and CDD in the pre pandemic period from 2015 through 2018. Figure 3-13 compares the actual load in 2021, 2022, and 2023 to the weather normalized load.

Figure 3-13 Real-time daily load and weather normalized load: October 2021 through September 2023

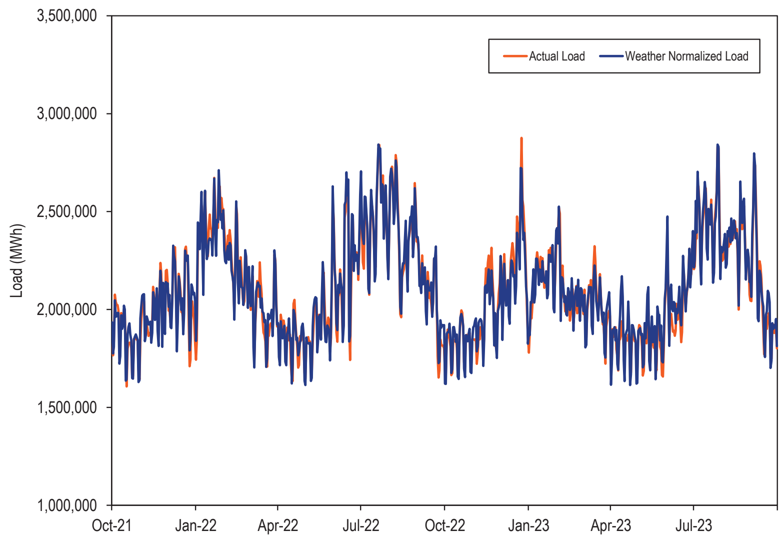


Table 3-9 compares the monthly actual load and the weather normalized load.

Actual load was 0.7 percent lower than weather normalized load in the first nine months of 2023.

Table 3-9 Actual load and weather normalized load: 2021 through September 2023

	2021			2022			2023		
	Actual Load	Weather Normalized Load	Percent Difference	Actual Load	Weather Normalized Load	Percent Difference	Actual Load	Weather Normalized Load	Percent Difference
Jan	66,905,774	68,256,113	(2.0%)	74,457,669	73,965,891	0.7%	66,854,012	66,649,610	0.3%
Feb	61,717,353	62,471,212	(1.2%)	62,556,707	61,833,819	1.2%	59,004,070	58,958,396	0.1%
Mar	58,258,178	60,459,812	(3.6%)	61,629,282	61,986,274	(0.6%)	62,646,982	62,266,981	0.6%
Apr	50,864,950	55,116,626	(7.7%)	55,444,404	55,267,453	0.3%	54,510,450	55,326,971	(1.5%)
May	53,430,088	57,904,128	(7.7%)	59,904,861	59,795,738	0.2%	56,932,509	58,261,677	(2.3%)
Jun	63,666,037	67,406,845	(5.5%)	66,521,445	67,334,205	(1.2%)	61,520,084	63,183,614	(2.6%)
Jul	78,749,183	80,856,404	(2.6%)	76,153,249	76,721,135	(0.7%)	75,863,322	75,626,393	0.3%
Aug	72,425,029	74,173,773	(2.4%)	74,839,426	74,939,704	(0.1%)	72,273,874	72,868,662	(0.8%)
Sep	58,683,018	60,988,913	(3.8%)	61,451,519	62,081,806	(1.0%)	62,094,609	62,532,876	(0.7%)
Oct	55,061,813	56,572,150	(2.7%)	56,233,707	56,324,880	(0.2%)			
Nov	55,993,432	57,678,640	(2.9%)	59,428,403	59,060,319	0.6%			
Dec	67,232,280	67,074,317	0.2%	70,003,632	68,138,490	2.7%			
Jan - Sep	62,744,401	65,292,647	(3.9%)	65,884,285	65,991,780	(0.2%)	63,522,212	63,963,909	(0.7%)

Day-Ahead Demand

The day-ahead hourly average demand in the first nine months of 2023, including DECs and UTCs, increased by 8.2 percent from the first nine months of 2022, from 105,195 MWh to 113,807 MWh.

The day-ahead hourly average demand in the first nine months of 2023, including DECs, UTCs and exports, increased by 8.3 percent from the first nine months of 2022, from 108,685 MWh to 117,715 MWh.

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

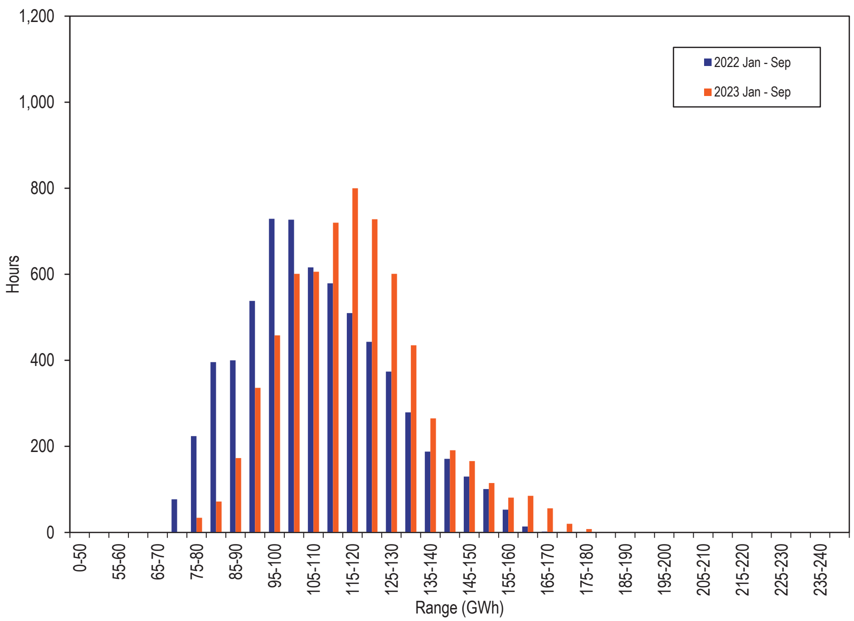
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero.
- **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. 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 total of the five types of cleared demand bids.

PJM Day-Ahead Demand Duration

Figure 3-14 shows the hourly distribution of the day-ahead demand for the first nine months of 2022 and 2023.

Figure 3-14 Distribution of day-ahead demand plus exports: January through September, 2022 and 2023[37]



PJM Day-Ahead Average Demand

Table 3-10 shows day-ahead hourly average demand for the first nine months of 2001 through 2023. The day-ahead hourly average demand in the first nine months of 2023, including DECs and UTCs, increased by 8.2 percent from the first nine months of 2022, from 105,195 MWh to 113,807 MWh.

Table 3-10 Day-ahead hourly average demand and demand plus exports: January through September, 2001 through 2023

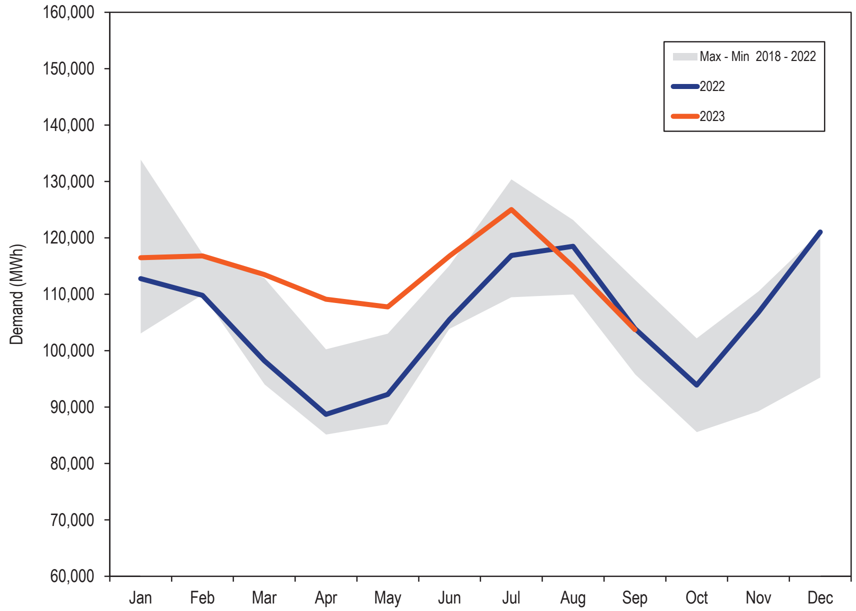
	PJM Day-Ahead Demand (MWh)				Year to Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
Jan-Sep	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2001	33,944	7,016	34,444	6,817	NA	NA	NA	NA
2002	41,634	11,073	41,726	11,120	22.7%	57.8%	21.1%	63.1%
2003	45,371	8,377	45,477	8,354	9.0%	(24.3%)	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%	(3.9%)
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%	3.0%	9.3%	2.5%
2014	156,542	23,584	160,425	23,533	7.9%	26.3%	8.1%	25.9%
2015	113,555	19,789	116,912	19,957	(27.5%)	(16.1%)	(27.1%)	(15.2%)
2016	129,048	22,492	132,405	22,801	13.6%	13.7%	13.3%	14.2%
2017	128,453	20,002	131,572	20,158	(0.5%)	(11.1%)	(0.6%)	(11.6%)
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%)
2020	109,850	19,762	113,188	20,089	(3.8%)	2.7%	(3.3%)	3.2%
2021	99,788	19,097	102,947	19,632	(9.2%)	(3.4%)	(9.0%)	(2.3%)
2022	105,195	18,664	108,685	18,945	5.4%	(2.3%)	5.6%	(3.5%)
2023	113,807	17,840	117,715	17,977	8.2%	(4.4%)	8.3%	(5.1%)

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

PJM Day-Ahead Monthly Average Demand

Figure 3-15 compares the day-ahead monthly average demand including decrement bids and up to congestion transactions in the first nine months of 2022 and 2023 with the historic five-year range. From March to June 2023, the day-ahead monthly average demand plus exports was higher than the maximum of the past five years, primarily as a result of the increase in UTCs.

Figure 3-15 Day-ahead monthly average demand plus exports: 2022 through September 2023



Real-Time and Day-Ahead Demand

Table 3-11 presents summary statistics for day-ahead and real-time demand for the first nine months of 2022 and 2023. The last two columns of Table 3-11 are day-ahead demand minus real-time demand. The first column is the total physical day-ahead load (fixed demand plus price-sensitive demand) less the physical real-time load. The second column is the total day-ahead demand less the total real-time demand.

The total physical day-ahead average load less the total physical real-time average load in the first nine months of 2023 increased 785 MWh from the first nine months of 2022, from -1,460 MWh to -675 MWh. The total day-ahead average demand less the total real-time average demand in the first nine months of 2023 increased 11,517 MWh from the first nine months of 2022, from 12,488 MWh to 24,006 MWh.

Table 3-11 Day-ahead and real-time demand (MWh): January through September, 2022 and 2023

		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	Load	Demand
Average	2022	88,395	660	5,237	10,904	3,490	108,685	90,514	96,196	(1,460)	12,488
	2023	86,125	469	4,921	22,292	3,907	117,715	87,269	93,709	(675)	24,006
Median	2022	85,663	435	5,023	10,221	3,551	106,272	87,952	94,072	(1,855)	12,200
	2023	84,106	450	4,466	22,583	3,862	116,652	84,969	91,244	(413)	25,409
Standard Deviation	2022	16,232	409	1,730	3,921	1,034	18,945	16,367	16,581	273	2,364
	2023	14,633	165	1,970	8,217	1,029	17,977	14,833	15,199	(35)	2,778
Peak Average	2022	96,476	714	5,721	11,866	3,574	118,351	98,384	104,158	(1,195)	14,193
	2023	93,770	501	5,668	24,383	3,917	128,238	94,626	101,086	(355)	27,151
Peak Median	2022	94,561	519	5,562	11,298	3,635	116,355	96,268	102,534	(1,188)	13,821
	2023	90,234	462	5,333	24,480	3,858	125,626	91,048	97,629	(351)	27,997
Peak Standard Deviation	2022	15,043	447	1,635	3,836	1,030	17,192	15,313	15,483	177	1,709
	2023	13,440	188	2,025	7,841	1,115	15,171	13,820	14,550	(192)	621
Off-Peak Average	2022	81,259	612	4,808	10,055	3,415	100,149	83,565	89,166	(1,694)	10,983
	2023	79,441	441	4,267	20,465	3,899	108,514	80,837	87,258	(954)	21,256
Off-Peak Median	2022	79,051	410	4,521	9,308	3,468	98,525	81,251	87,352	(1,790)	11,172
	2023	77,486	443	3,887	20,837	3,867	106,516	78,967	85,688	(1,038)	20,827
Off-Peak Standard Deviation	2022	13,703	365	1,698	3,797	1,031	16,111	13,945	14,166	124	1,945
	2023	12,152	136	1,666	8,102	948	14,935	12,520	12,599	(232)	2,336

Figure 3-16 shows the average cleared volumes of day-ahead and real-time demand in the first nine months of 2023. The day-ahead demand includes day-ahead load, decrement bids, up to congestion transactions, and day-ahead exports. The real-time demand includes real-time load and real-time exports.

Figure 3-16 Day-ahead and real-time demand (Average hourly volumes): January through September, 2023

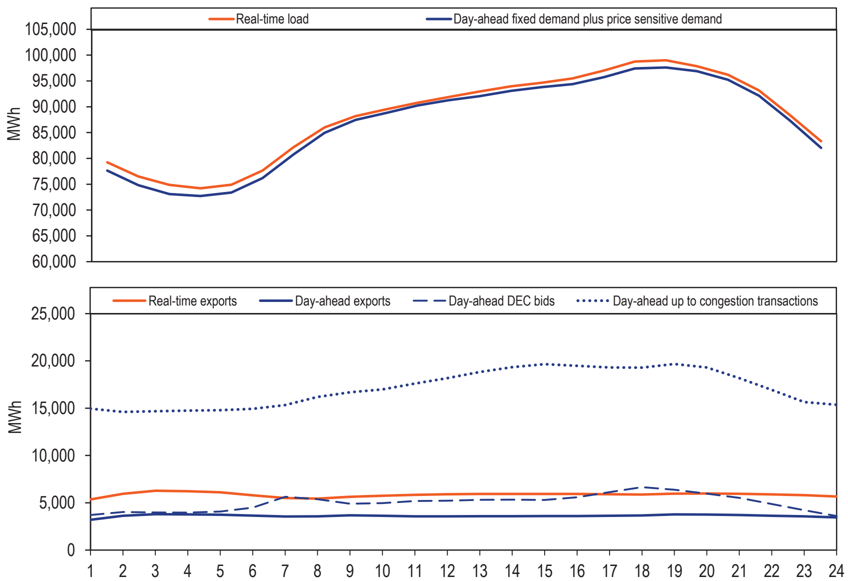
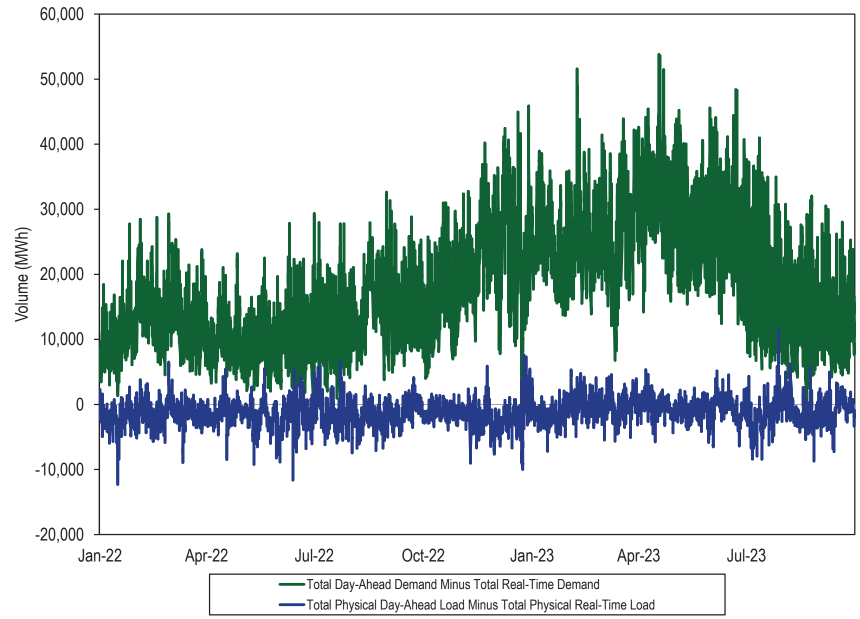


Figure 3-17 shows the difference between the day-ahead and real-time daily average demand in the first nine months of 2022 and 2023.

Figure 3-17 Difference between day-ahead and real-time daily average demand: 2022 through September 2023



Market Behavior

Generator Offers

Generators indicate their availability for commitment and dispatch in the day-ahead market through their offers. Commitment availability status is economic, must run, or unavailable. Dispatch availability status is defined by the difference between the economic minimum and maximum output levels. PJM will clear units that select must run status in the offer in the day-ahead market up to their economic minimum MW regardless of economics. Units may set their economic minimum MW equal to their economic maximum MW, also called block loading, or they may raise the economic minimum MW to a point between the actual economic minimum and the economic maximum. Must run units may commit at economic minimum and permit the balance to be dispatchable or block load the full output of the unit. If units select economic commitment status, the day-ahead market will commit them based on their offers.

The Must Run column in Table 3-12 is the submitted offer MW of units offering with must run commitment status. The Eco Min column in Table 3-12 is the economic minimum MW of units offering with economic commitment status. The dispatchable range in Table 3-12 is the percent of MW offered by price range, between the economic minimum MW and economic maximum MW for all available units. Some units, like wind and solar, offer a dispatchable range in the day-ahead market although their availability in real time is determined by the presence of sun and wind rather than economics.

Units may designate all or a portion of their capacity as emergency MW. Table 3-12 shows that 0.6 percent of offered MW are emergency MW. In some cases, higher shares of emergency MW result from offer behavior that does not accurately represent the availability of the emergency MW in real time.

In the day-ahead market in the first nine months of 2023, 23.3 percent of MW were offered as must run, 32.1 percent of MW were offered as the economic minimum MW for dispatchable units, 44.0 percent of MW were offered as dispatchable, and 0.6 percent of MW were offered as emergency maximum MW.

Table 3-12 Dispatchable status of day-ahead energy offers: January through September, 2023

			Dispatchable Range											
Unit Type	Must Run	Eco Min	($300) - $0	$0 - $25	$25 - $50	$50 - $75	$75 - $100	$100 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1000	Emergency MW	Dispatchable Percent
CC	8.2%	35.6%	(0.1%)	17.2%	18.2%	9.0%	3.8%	5.0%	2.6%	0.2%	0.1%	0.0%	0.2%	56.0%
CT	0.5%	57.4%	0.0%	1.0%	7.5%	7.2%	5.3%	8.4%	9.3%	1.7%	0.4%	0.1%	1.3%	40.8%
Diesel	7.9%	84.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.5%	0.0%	0.0%	0.0%	0.0%	7.5%
Hydro	82.8%	0.0%	17.2%	0.0%	0.0%	-0.0%	0.0%	-0.0%	0.0%	-0.0%	0.0%	-0.0%	0.0%	17.2%
Nuclear	89.9%	6.7%	2.4%	0.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.3%
Solar	16.4%	1.0%	71.9%	3.4%	3.1%	1.1%	0.8%	1.6%	0.7%	0.0%	0.0%	0.0%	0.0%	82.6%
Steam - Coal	27.7%	24.6%	0.1%	4.5%	19.7%	8.3%	5.4%	5.2%	1.2%	1.9%	0.0%	0.0%	1.3%	46.4%
Steam - Other	5.0%	22.1%	1.3%	4.8%	11.7%	9.3%	8.2%	13.2%	21.6%	2.4%	0.0%	0.0%	0.3%	72.5%
Wind	4.5%	0.8%	82.0%	6.4%	3.6%	1.2%	0.5%	0.5%	0.4%	0.0%	0.0%	0.1%	0.0%	94.7%
Other	15.9%	48.3%	5.0%	3.4%	4.2%	2.6%	0.1%	1.0%	15.3%	1.0%	0.1%	0.0%	3.0%	32.8%
All Units	23.1%	31.7%	2.3%	7.8%	12.3%	6.8%	4.0%	5.5%	4.9%	0.9%	0.1%	0.0%	0.6%	44.7%

Hourly Offers and Intraday Offer Updates

All participants may make hourly offers. Participants must opt in on a monthly basis to make intraday offer updates. Participants that have opted in can make updates only based on the process defined in their fuel cost policies. Table 3-13 shows the daily average number of units that make hourly offers, that opted in to intraday offer updates and that make intraday offer updates. In the first nine months of 2023, an average of 346 units per day made hourly offers, an increase of seven units from the first nine months of 2022. In the first nine months of 2023, 539 units opted in for intraday offer updates, an increase of 55 units from the first nine months of 2022. In the first nine months of 2023, an average of 131 units made intraday offer updates each day, a decrease of two units from the first nine months of 2022.

Table 3-13 Daily average number of units making hourly offers, opted in for intraday offers and making intraday offer updates: January through September, 2022 and 2023

	Fuel Type	2022 (Jan-Sep)	2023 (Jan-Sep)	Difference
Hourly Offers	Natural Gas	311	309	(2)
	Other Fuels	28	37	9
	Total	339	346	7
Opt In	Natural Gas	391	410	19
	Other Fuels	93	129	36
	Total	484	539	55
Intraday Offer Updates	Natural Gas	126	124	(2)
	Other Fuels	7	7	0
	Total	133	131	(2)
Total Units with nonzero offers		987	947	(40)

ICAP Must Offer Requirement

Generation capacity resources are required to offer their full ICAP MW into the day-ahead and real-time energy market, or report an outage for the difference.[38] The full installed capacity (ICAP) is the ICAP of the resources that cleared in the capacity market. This is known as the ICAP must offer requirement.

38 OA Schedule 1 § 1.10.1A(d).

Solar, wind, landfill gas, hydro and batteries can satisfy the must offer requirement by self scheduling or offering as dispatchable. There is no defined amount of capacity that these resources must offer. The must offer requirement is thus not applied to these intermittent resource types and compliance is not enforceable.

The current enforcement of the ICAP must offer requirement is inadequate.[39] The problem is a complex combination of generator behavior, and inadequate and inconsistent reporting tools that are not synchronized. Compliance is subject to mistakes and susceptible to manipulation.

Resources are required to submit their available capacity in three different systems. Resources are required to make offers in the energy market. Resources are required to report outages in the Dispatch Application Reporting Tool (eDART) in advance or in real time. Resources are required to report outages in the Generator Availability Data System (eGADS) after the fact. The three applications are not linked and there is no formal process to ensure consistency.

For example, ambient ratings are an issue. When the weather is hotter than test conditions, the capacity of some units is reduced below the ICAP levels. While this fact may be reported by unit owners in eDART and reflected in lower offered MW in the energy market, the derates are not reported as outages in eGADS and are therefore not included as outages for purposes of defining capacity using EFORd. For planning purposes, PJM acknowledges this discrepancy, but instead of reflecting the derates in the supply offers from the units that are actually derated, PJM increases the demand for capacity to account for the loss of supply due to ambient derates.[40]

The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate.

39 PJM compares the data submitted in eDART to the data submitted in Markets Gateway using the eDART Gen Checkout. Generators are supposed to acknowledge their Gen Checkout reports. Manual 10 and the eDART User Guide do not specify what acknowledging the Gen Checkout report means, any requirements to acknowledge the Gen Checkout report or any consequences for not doing so. Gen Checkout is also only triggered if generators fail by more than defined thresholds.

40 *See* "Capacity Value Accreditation Concepts in the Reliability Pricing Model (RPM)," slide 13, PJM presentation to the Resource Adequacy Senior Task Force. (August 8, 2022) <https://www.pjm.com/-/media/committees-groups/task-forces/rastf/2022/20220808/item-05---capacity-value-accreditation-concepts-in-the-reliability-pricing-model.ashx>.

The MMU recommends that intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources.

Table 3-14 shows average hourly MW, for each month, that violated the ICAP must offer requirement in the first nine months of 2023. On average for all hours, 2,206 MW did not meet the ICAP must offer requirement, but for 10 percent of the hours 4,498 MW did not meet the must offer requirement. These MW levels are larger than the reserve shortages that trigger scarcity pricing and larger than most supply contingencies that lead to synchronized reserve events.

Table 3-14 Average hourly estimated capacity (MW) failing the ICAP must offer requirement: January through September, 2023

Month	90th Percentile	Average	10th Percentile
Jan-23	2,218	1,257	265
Feb-23	1,252	676	295
Mar-23	1,440	808	364
Apr-23	5,299	3,781	1,878
May-23	5,151	4,449	3,832
Jun-23	4,158	3,323	2,603
Jul-23	2,750	2,030	1,232
Aug-23	2,196	1,540	982
Sep-23	2,650	1,918	1,099
2023	4,498	2,206	514

The outage data reported in eGADS do not exactly match the energy market data submitted in Markets Gateway. For example, economic maximum MW levels submitted in Markets Gateway that reflect expected ambient conditions (including ambient derates) can be inconsistent with the maximum capability submitted in eGADS. Another example is the start and end times of planned outages in the shoulder months. In many situations units are derated in Markets Gateway to reflect an upcoming planned outage for which the unit must ramp down over an extended period but in eGADS the outage start time is not reported until the unit is completely unavailable. These differences can result in units not meeting their ICAP must offer requirement.

The MMU recommends that PJM integrate all the outage reporting tools in order to enforce the ICAP must offer requirement, ensure that outages are reported correctly and eliminate reporting inconsistencies. Generators currently submit availability in three different tools that are not integrated, Markets Gateway, eDART and eGADS.

Emergency Maximum MW

Generation resources are offered with economic maximum MW and emergency maximum MW. The economic maximum MW is the output level the resource can achieve following economic dispatch. The emergency maximum MW is the output level the resource can achieve when emergency conditions are declared by PJM. The MW difference between the two ratings equals emergency maximum MW. The PJM market rules allow generators to include emergency maximum MW as part of ICAP offered in the capacity market.[41]

Generation resources have to meet one of four conditions to offer any MW as emergency in the energy market: environmental limits imposed by a federal, state or other governmental agency that significantly limit availability; fuel limits beyond the control of the generation owner; temporary emergency conditions that significantly limit availability; or temporary MW additions not ordinarily available.[42]

The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy.[43] Capacity resources should offer their full output in the energy market and subject to economic dispatch. The result will be incentives for correct reporting of ICAP, more efficient energy market pricing, and a reduction in the need for manual overrides by PJM dispatchers during emergency conditions. Resources that do have capacity that can only be achieved with extraordinary measures could offer such capacity in the energy market but should not take on a capacity market obligation.

Table 3-15 shows average hourly maximum emergency MW, for each month. The levels of maximum emergency MW change hourly, daily and seasonally. For example, in May 2023, 10 percent of hours had maximum emergency MW

41 See 151 FERC ¶ 61,208 at P 476 (2015).
42 OA Schedule 1 § 1.10.1A(d).
43 This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See PJM Filing, Attachment A (Redlines of OA Schedule 1 § 1.10.1A(d), EL15-29-000 (December 12, 2014). FERC rejected the proposed change. See 151 FERC ¶ 61,208 at P 476 (2015).

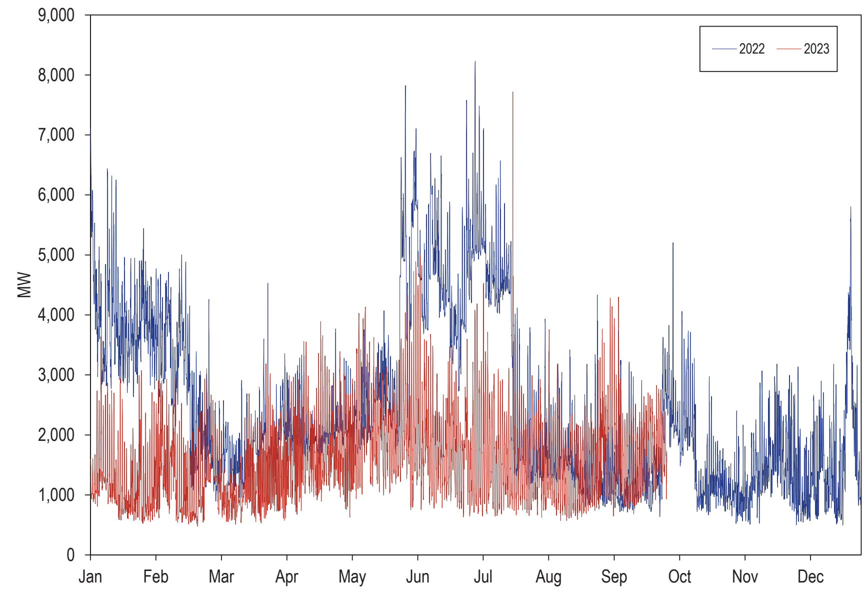
greater than or equal to 3,155 MW while 10 percent of hours had maximum emergency MW less than 1,206 MW. The hourly average, in the first nine months of 2023, was 1,621 MW offered as maximum emergency, 35.8 percent lower than in the first nine months of 2022.

Table 3-15 Maximum emergency MW by month: January through September, 2023

Month	90th Percentile	Average	10th Percentile
Jan-23	2,338	1,244	656
Feb-23	2,370	1,350	624
Mar-23	2,132	1,260	679
Apr-23	2,753	1,761	1,057
May-23	3,155	2,073	1,206
Jun-23	3,027	1,895	911
Jul-23	2,835	1,703	769
Aug-23	2,261	1,532	751
Sep-23	2,602	1,766	934
2023	2,640	1,621	769

Figure 3-18 shows maximum emergency MW by hour in 2022 and the first nine months of 2023. The increase in maximum emergency MW in January 2022 through February 2022 and again in June 2022 was mainly due to coal availability, consumables inventory shortages and environmentally limited units. The increase in December 2022 was mainly caused by low oil inventories and environmentally limited oil fired units after higher than normal operation on December 23 and 24, 2022.

Figure 3-18 Maximum Emergency MW by hour: 2022 and January through September, 2023



Parameter Limited Schedules

Cost-Based Offers

All resources in PJM are required to submit at least one cost-based offer. Cost-based offers, submitted by capacity resources for a defined set of technologies, are parameter limited based on unit specific parameter limits. Nuclear, wind, solar and hydro units are not subject to 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 resources, the price-based parameter limited schedule is used by PJM for committing generation resources when a maximum emergency generation alert is declared. For capacity resources, the price-based parameter limited schedule is used by PJM for committing generation resources when hot weather alerts and cold weather alerts are declared.

The current implementation is not consistent with the goal of having parameter limited schedules, which is to prevent the use of inflexible operating parameters to exercise market power. 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. The result is that PJM does not select the lowest cost schedule and allows market power to be exercised. The Commission recognized this flaw in the implementation of market power mitigation in its order to show cause, issued June 17, 2021.[44]

PJM did not recognize or attempt to address the market power issue in 2022 or the first nine months of 2023.[45] PJM has an opportunity to address the market power issue in the implementation of enhanced combined cycle modelling development. The process that PJM currently uses to determine the least cost schedule is computationally intensive in the day-ahead market on hot and cold weather alert days. Implementing the MMU's recommendations would both solve the market power mitigation issues and decrease the day-ahead market solution time.[46]

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market when units are committed after failing the TPS test for transmission constraints in the first nine months of 2023. The analysis includes units with technologies that are subject to parameter limits and offer both price-based and cost-based schedules.[47] Table 3-16 shows the number and percentage of day-ahead unit run hours that failed the TPS test but were committed on price schedules. Table 3-16 shows that 32.4 percent of unit hours for units that failed the day-ahead TPS test were committed on price-based schedules that were less flexible than their cost-based schedules. For effective market power mitigation there would be zero units that fail the TPS test committed with parameters less flexible than their cost-based schedules.

Table 3-16 Parameter mitigation for units failing the day-ahead TPS test: January through September, 2023

Day-ahead Commitment For Units That Failed TPS Test	Day-ahead Unit Hours	Percent Day-ahead Unit Hours
Committed on price schedule less flexible than cost	24,407	32.4%
Committed on price schedule as flexible as cost	6,228	8.3%
Total committed on price schedule without parameter limits	30,635	40.6%
Committed on cost (cost capped)	43,337	57.5%
Committed on price PLS	1,424	1.9%
Total committed on PLS schedules (cost or price PLS)	44,761	59.4%

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market for units in zones where a cold weather alert or a hot weather alert or maximum generation emergency was declared in the first nine months of 2023. PJM declared cold weather alerts on three days and twenty-one hot weather alerts in the first nine months of 2023.[48] The analysis includes units with technologies that are subject to parameter limits, with a capacity commitment, in the zones where the cold or hot weather alerts were declared. Table 3-17 shows that 52.5 percent of unit hours during weather alerts in the day-ahead energy market were committed on price-based schedules that were less flexible than their price PLS schedules.[49] Effective market power mitigation would result in zero units committed during cold and hot weather alerts with parameters less flexible than their price PLS schedules.

44 See 175 FERC ¶ 61,231 (2021).
45 PJM began a stakeholder process to address the computational time in the first six months of 2023 but PJM's proposals failed to address the market power issue.
46 See "Offer Capping Issue Charge," MMU Presentation to the Market Implementation Committee (January 11, 2023), <http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Offer_Capping_and_Combined_Cycle_Modeling_Presentation_20230111.pdf>.
47 Nuclear, wind, solar and hydro units are not subject to parameter limits.
48 *2022 Annual State of the Market Report for PJM*, Section 3: Energy Market, at Emergency Procedures.
49 Nuclear, wind, solar and hydro units are not subject to parameter limits.

Table 3-17 Parameter mitigation during weather alerts: January through September, 2023

Day-ahead Commitment During Hot And Cold Weather Alerts	Day-ahead Unit Hours	Percent Day-ahead Unit Hours
Committed on price schedule less flexible than PLS	225,126	52.5%
Committed on price schedule as flexible as PLS	100,123	23.4%
Total committed on price schedule without parameter limits	325,249	75.9%
Committed on cost (cost capped)	14,963	3.5%
Committed on price PLS	88,514	20.6%
Total committed on PLS schedules (cost or price PLS)	103,477	24.1%

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 best solution to the use of inflexible parameters is to require the use of flexible parameters in all offers at all times for capacity resources. Capacity resources are paid to be flexible but that payment will not result in flexible offers in the energy market, the only place it matters, unless there are explicit requirements that energy offers from capacity resources incorporate that flexibility.

If flexible parameters are not required at all times, the use of flexible parameters should be required whenever a unit fails the TPS test and whenever the system is facing emergency conditions. This would require that PJM apply the full set of approved unit specific parameters to a resource that offers any inflexible parameter under these conditions. The selection of the lowest cost offer, based on the financial parameters, would include the PLS parameters for all schedules.

The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times.

Currently, PJM commits units on either a cost-based or a price-based schedule. For example, selecting a price-based schedule means selecting the combination of all the operating and financial parameters of such schedule. The financial parameters and the operating parameters should be addressed separately. This approach would simplify the schedule structure implemented in PJM and would allow PJM to effectively mitigate inflexible operating parameters. The simplified modelling would speed the processing time of the day-ahead market, facilitating the implementation of enhanced combined cycle modelling.

The MMU recommends, if the MMU's preferred recommendation is not implemented, that in order to ensure effective market power mitigation, PJM always enforce parameter limited values for all schedules when the TPS test is failed and during high load conditions such as cold and hot weather alerts and emergency conditions. This requires that PJM separately mitigate the operating parameters and the financial parameters of the offers (incremental offer, startup cost, and no load cost) or to only use parameter limited schedules on alert days and when a resource fails the TPS test.[50]

Parameter Limits

Beginning June 1, 2020, all capacity resources, including resources in FRR capacity plans, are capacity performance resources. The unit specific parameter limits for capacity performance 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.

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

50 *See* "Comments of the Independent Market Monitor for PJM," Docket No. EL21-78 (October 15, 2021) at 18 - 19.

resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as committed capacity resources.

Unit Specific Adjustment Process

Market participants can request an adjustment to the default values of parameter limits for 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 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 boiler based 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.[51] 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 3-18 shows, for the delivery year beginning June 1, 2023, the number of units with approved unit specific parameter limit adjustments, and the number of units that used the default parameter limits published by PJM.

Table 3-18 Adjusted unit specific parameter limit statistics: 2023/2024 Delivery Year

Technology Classification	Units Using Default Parameter Limits	Units with One or More Adjusted Parameter Limits	Percent of Units with One or More Adjusted Parameter Limits
Aero CT	120	37	23.6%
Frame CT	159	105	39.8%
Combined Cycle	94	32	25.4%
Reciprocating Internal Combustion Engines	59	4	6.3%
Solid Fuel NUG	34	6	15.0%
Oil and Gas Steam	9	12	57.1%
Subcritical Coal Steam	4	48	92.3%
Supercritical Coal Steam	1	32	97.0%
Pumped Storage	7	1	12.5%

Real-Time Values

The Commission rejected PJM's proposed revisions to add RTV rules to the tariff in an order issued on May 28, 2021. In its order, the Commission recognized that RTVs can be used to exercise market power by withholding generation and avoiding market power mitigation.[52]

The real-time values submittal process was never defined in the PJM Operating Agreement. The process was defined only in PJM Manual 11. While there are a number of options for providing real-time unit status to PJM operators, PJM created a mechanism for the submission of such values called real-time values (RTVs). Unlike parameter exceptions, the use of real-time values made a unit ineligible for make whole payments, unless the market seller could justify such operation based on an actual constraint.[53] In the case of the notification time parameter, start time parameter, minimum run time and minimum down time parameters, a longer real-time value decreases the likelihood of the unit being committed, making the RTV a mechanism for exercising market power through withholding and for failing to meet the obligations of capacity resources.

51 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>.

52 175 FERC ¶ 61,171 (2021).

53 See OA Schedule 1 § 3.2.3(e).

PJM's proposed RTV mechanism was rejected by the Commission because it would weaken the existing market power mitigation rules including parameter limited schedules.[54]

Beginning August 1, 2021, PJM provides guidance to market sellers that it will no longer accept real-time value submissions for economic reasons, such as due to choosing not to staff a unit. In its order to show cause issued on June 17, 2021, the Commission stated its concern that "the PJM Tariff appears to be unjust and unreasonable because it fails to contain provisions governing what happens if a seller is unable to meet its unit-specific parameters in real time."[55] In its response to the Commission's order, PJM proposed tariff updates to allow generators to submit temporary exceptions during the operating day.[56] These proposed rules require market sellers to justify that the request is based on a physical and actual constraint by submitting supporting documentation within three business days, consistent with the existing temporary parameter exception process. Without a response from FERC on its proposed rules, in the first nine months of 2023, PJM revised Manual 11 to incorporate its current practice of treating real-time values as temporary exceptions submitted in real time. This approach was in PJM's proposed rules that have been submitted to but not yet approved by FERC.[57] On September 11, 2023, PJM and the MMU filed a joint motion to expedite action with respect to the acceptance of PJM's proposal to replace real time values with temporary exceptions. PJM and the MMU requested an acceptance date of December 1, 2023.[58]

Units that override their turn down ratio (economic maximum divided by economic minimum) either use Real-Time Values or PJM's fixed gen flag, which functions identically to a real-time value.[59] These resources operate on their parameter limited schedules but override their output limit parameters with no consequence. The only difference between a Real-Time Value to override the turn down ratio parameter and the fixed gen flag is that the fixed gen resources receive uplift payments. These resources receive inefficient levels of uplift payments when they have market power. The September 15th Response does not address unstaffed units that refuse to meet their notification time or units that refuse to perform to their turn down ratio parameter by using fixed gen.

There are two options to address the real-time exceptions issue. The immediate option is to clearly define acceptable and unacceptable reasons for requesting a real-time exception. In the case of unacceptable reasons, the unit would not be paid a portion of its otherwise applicable capacity market revenues, e.g. the daily value, if it included the modified parameter values in its offer. The MMU recommends that PJM require generators that violate their approved turn down ratio (by either using the fixed gen option or increasing their economic minimum) to use the temporary parameter exception process that requires market sellers to demonstrate that the request is based on a physical and actual constraint.

The better option, consistent with the no excuses approach of the capacity performance paradigm and consistent with long term incentives for flexibility, is to not pay any capacity resources an appropriate portion of the daily capacity value of the resource for days when it is not fully available consistent with its parameter limited schedule. If flexibility is valued as a generator attribute, the market design should not provide incentives to be inflexible. An effective market design should reward flexible operation, and ensure that capacity resources are paid for their capacity only when it meets their required level of flexibility. Without clearly defined consequences, market sellers will continue to submit inflexible parameters. The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits.[60]

54 175 FERC ¶ 61,171 at P 36 (2021).
55 175 FERC ¶ 61,231 at P 17 (2021).
56 PJM. "Answer of PJM Interconnection LLC," Docket No. EL21-78 (September 15, 2021)("September 15th Response").
57 *See* "Manual 11 Periodic Review: Real Time Values," PJM Presentation to the Market Implementation Committee (April 11, 2023), <https://pjm.com/-/media/committees-groups/committees/mic/2023/20230412/20230412-item-02-1---real-time-values-manual-11-revisions.ashx>.
58 PJM and MMU. "Joint Motion of PJM Interconnection, LLC, and the Independent Market Monitor to Expedite Action with Respect to Acceptance of PJM's Proposal to Replace Real Time Values with Temporary Exceptions Docket No. EL21-78 (September 11, 2023).
59 PJM Markets Gateway User Guide, Section 6.9: Self-schedule a Generating Unit and Ignore PJM Dispatch Instruction at 41, <https://www.pjm.com/~/media/etools/markets-gateway/markets-gateway-user-guide.ashx>.
60 *See* Monitoring Analytics LLC, "Real-Time Values," presented at the Markets Implementation Committee Special Session (October 7, 2020) at 12, *which can be accessed at* <https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20201007/20201007-item-06b-real-time-values-imm.ashx>.

Generator Flexibility Incentives under Capacity Performance

In its June 9, 2015, 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.[61] The Commission directed that capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.[62] 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.[63]

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

61 151 FERC ¶ 61,208 at P 437 (2015) (September 9th Order).
62 *Id* at P 439.
63 *Id* at P 440.

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

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

Parameter Impacts of Gas Pipeline Conditions

During extreme cold weather conditions, and more recently, also during hot 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. Table 3-19 shows the number of units, and the installed capacity MW that submitted parameter exception requests for a 24 hour minimum run time due to gas pipeline restrictions. In the first nine months of 2023, there were 75 units in PJM with a total installed capacity of 9,824 MW that requested a 24 hour minimum run time on their parameter limited schedules based on pipeline restrictions.

Table 3-19 Units with 24 hour minimum run times due to gas pipeline restrictions: January through September, 2018 through 2023

Year (Jan - Sep)	Number of Units With 24 Hour Minimum Run Time Exceptions	Installed Capacity (MW) With 24 Hour Minimun Run Time Exceptions
2018	23	3,314
2019	37	5,616
2020	8	3,448
2021	53	7,145
2022	60	7,212
2023	75	9,824

The increase in units requesting 24 hour minimum run times is a result of pipelines enforcing the pipeline tariff ratable take provisions. Pipelines have the authority to require ratable takes under their tariffs at any time although pipelines do not enforce ratable takes on a routine basis. Some generators have also requested extremely long notification times based on pipeline nomination deadlines. (See Table 3-67.) When pipelines enforce these deadlines, generators cannot obtain gas to flow for a given market hour once the deadline has passed for that hour and therefore they cannot start according to their normal notification plus start times (normally less than 30 minutes). For example, at 1700 EPT, the next nomination cycle is intraday 3 (ID3). The ID3 deadline is 2000 EPT for gas to flow starting at 2300 EPT. When these nomination deadlines are enforced, at 1700 EPT, a gas unit can only start at 2300 EPT (or in 6 hours). This effectively increases the time to start (notification time plus start time) from 30 minutes to 6 hours. The long notification times make the units unavailable for commitment in ITSCED and the units can only be committed manually in real time. Generators may request temporary exceptions based on pipeline restrictions in order to provide PJM with offers that accurately reflect their capabilities. Units operating inflexibly due to pipeline restrictions are eligible for uplift. Temporary exceptions should be limited to the duration of restrictions imposed by pipelines.

During Winter Storm Elliott, PJM paid $5.3 million in uplift to CTs with 24 hour minimum run times, mostly in the ComEd Zone.

The MMU recommends that PJM only approve temporary exceptions that are based on pipeline tariff terms and/or pipeline notices when actually enforced by the pipelines.

Virtual Offers and Bids

Market participants may make virtual offers and bids in the PJM Day-Ahead Energy Market, and such offers and bids may be marginal.

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. Because virtual positions do not require physical generation or load, participants must buy or sell out of their virtual positions at real-time energy market prices. On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, interfaces and residual aggregate metered load nodes, and limiting the eligible bidding points for INCs and DECs to the same nodes plus active generation and load nodes.[64] Up to congestion transactions may be submitted between any two buses on a list of 47 buses eligible for up to congestion transaction bidding.[65] 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 3-19 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 the first nine months of 2023.

Figure 3-19 Day-ahead aggregate supply curves: 2023 example day

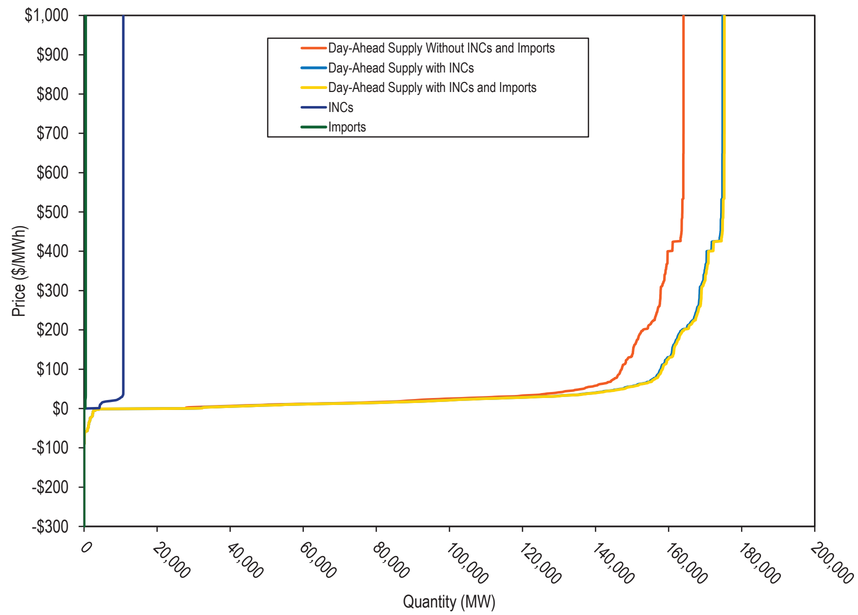


Table 3-20 shows the hourly average number of cleared and submitted increment offers and decrement bids by month in 2022 and the first nine months of 2023. The hourly average submitted increment offer MW increased by 14.8 percent and cleared increment MW increased by 21.3 percent in the first nine months of 2023 compared to the first nine months of 2022. The hourly average submitted decrement bid MW decreased by 10.3 percent and cleared decrement MW decreased by 5.7 percent in the first nine months of 2023 compared to the first nine months of 2022.

64 162 FERC ¶ 61,139 (2018).
65 Prior to November 1, 2012, 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. For the list of eligible sources and sinks for up to congestion transactions, see www.pjm.com *"OASIS-Source-Sink-Link.xls,"*<http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>.

Table 3-20 Average hourly number of cleared and submitted INCs and DECs by month: January 2022 through September 2023

		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
2022	Jan	2,898	7,135	308	1,069	6,513	14,228	375	1,559
2022	Feb	3,743	8,639	359	1,216	6,078	13,359	348	1,370
2022	Mar	4,072	9,403	337	1,143	5,579	12,511	256	1,074
2022	Apr	3,909	8,696	342	1,069	3,833	11,008	196	1,026
2022	May	3,588	8,381	319	1,029	4,960	12,441	247	1,072
2022	Jun	3,467	7,708	249	909	4,719	11,482	234	1,032
2022	Jul	3,060	7,249	266	1,068	4,451	10,703	192	976
2022	Aug	3,112	6,696	259	973	4,889	11,092	241	997
2022	Sep	3,352	7,280	257	1,109	6,157	11,806	287	1,003
2022	Oct	3,603	7,979	304	969	4,813	11,978	320	1,280
2022	Nov	4,586	9,985	373	1,268	4,504	12,304	307	1,229
2022	Dec	3,587	8,012	322	1,090	4,637	12,786	310	1,386
2022	Annual	3,578	8,089	308	1,075	5,089	12,137	276	1,167
2023	Jan	3,870	7,847	319	949	4,421	9,941	307	1,076
2023	Feb	4,994	9,786	426	1,190	4,583	9,732	258	933
2023	Mar	4,578	9,008	415	1,068	4,613	11,030	316	1,113
2023	Apr	4,960	10,697	374	1,036	3,515	9,803	275	1,091
2023	May	4,648	9,200	393	1,050	4,126	10,193	284	984
2023	Jun	4,171	8,328	374	1,008	5,515	11,400	426	1,272
2023	Jul	3,421	8,403	278	952	5,725	11,608	593	1,590
2023	Aug	3,177	8,604	283	953	6,267	11,679	337	1,013
2023	Sep	3,939	9,612	366	1,060	5,472	11,539	291	961
2023	Jan-Sep	4,185	9,041	358	1,028	4,920	10,779	344	1,117

Table 3-21 shows the average hourly number of up to congestion transactions and the average hourly MW by month in 2022 and the first nine months of 2023. The volume of bid and cleared up to congestion transactions increased dramatically during this time. The hourly average submitted up to congestion bid MW increased by 121.5 percent and cleared up to congestion bid MW increased by 104.4 percent in the first nine months of 2023 compared to the first nine months of 2022. However, the MW of submitted UTCs decreased to early 2022 levels in August and September 2023.

Table 3-21 Average hourly cleared and submitted up to congestion bids by month: January 2022 through September 2023

		Up to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2022	Jan	8,268	28,791	478	1,322
2022	Feb	11,908	31,383	632	1,452
2022	Mar	10,921	34,887	521	1,366
2022	Apr	9,030	37,400	440	1,342
2022	May	8,616	34,312	438	1,277
2022	Jun	10,213	31,573	520	1,305
2022	Jul	11,009	35,453	624	1,669
2022	Aug	15,007	48,449	756	2,143
2022	Sep	13,259	48,064	853	2,245
2022	Oct	14,738	53,955	739	2,237
2022	Nov	21,784	74,103	889	2,633
2022	Dec	24,019	82,190	1,000	2,797
2022	Annual	13,239	45,134	658	1,818
2023	Jan	23,708	69,113	952	2,522
2023	Feb	24,242	87,218	1,003	3,156
2023	Mar	24,834	115,463	961	3,942
2023	Apr	30,027	129,360	1,043	3,719
2023	May	27,910	110,474	1,053	3,251
2023	Jun	26,248	90,763	1,106	3,242
2023	Jul	18,777	59,561	1,011	2,715
2023	Aug	12,567	36,486	830	2,035
2023	Sep	12,574	34,771	686	1,539
2023	Jan-Sep	22,292	81,361	960	2,900

Table 3-22 shows the average hourly number of day-ahead import and export transactions and the average hourly MW from January 2022 through September 2023. In the first nine months of 2023, the average hourly submitted import transaction MW increased by 28.9 percent and the average hourly cleared import transaction MW increased by 29.2 percent compared to the first nine months of 2022. In the first nine months of 2023, the average hourly submitted export transaction MW increased by 11.9 percent and the average hourly cleared export transaction MW increased by 12.2 percent compared to the first nine months of 2022.

Table 3-22 Hourly average day-ahead number of cleared and submitted import and export transactions by month: January 2022 through September 2023

		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
2022	Jan	295	322	4	5	4,349	4,360	35	36
2022	Feb	271	298	4	4	4,639	4,647	37	37
2022	Mar	169	196	3	3	3,822	3,842	27	27
2022	Apr	247	269	4	4	2,085	2,110	19	20
2022	May	428	441	5	5	2,521	2,566	21	21
2022	Jun	310	320	3	3	3,084	3,118	31	31
2022	Jul	268	283	3	3	3,217	3,265	31	31
2022	Aug	308	316	3	3	4,010	4,046	32	32
2022	Sep	356	396	2	3	3,830	3,870	29	30
2022	Oct	340	356	4	4	2,786	2,813	19	19
2022	Nov	419	455	4	5	2,819	2,813	24	24
2022	Dec	471	508	4	5	3,840	3,926	30	31
2022	Annual	325	349	4	4	3,412	3,443	28	28
2023	Jan	740	843	7	8	3,879	3,944	28	28
2023	Feb	646	695	6	6	4,064	4,086	29	29
2023	Mar	371	402	3	4	3,739	3,779	28	29
2023	Apr	355	365	4	4	3,029	3,043	25	26
2023	May	327	346	3	4	2,875	2,876	20	20
2023	Jun	308	322	3	3	4,429	4,439	31	31
2023	Jul	169	172	2	2	4,566	4,592	33	33
2023	Aug	126	127	2	2	4,627	4,637	33	33
2023	Sep	187	220	2	3	3,998	4,026	28	29
2023	Jan-Sep	380	405	4	4	3,911	3,935	28	29

Table 3-23 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 2022 through September 2023.[66]

Table 3-23 Type of day-ahead marginal resources: January 2022 through September 2023

	2022						2023					
	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	20.3%	0.1%	34.5%	27.6%	17.4%	0.1%	11.3%	0.8%	57.0%	18.4%	12.5%	0.0%
Feb	14.9%	0.1%	39.9%	25.5%	19.6%	0.0%	12.4%	0.1%	57.2%	15.2%	14.8%	0.3%
Mar	16.4%	0.2%	38.5%	20.4%	24.6%	0.0%	12.6%	0.1%	57.6%	16.9%	12.7%	0.1%
Apr	20.8%	0.3%	33.4%	18.5%	27.0%	0.1%	9.2%	0.1%	60.2%	15.3%	15.1%	0.0%
May	17.4%	0.4%	38.8%	22.5%	20.8%	0.1%	11.2%	0.0%	59.9%	14.8%	13.9%	0.2%
Jun	16.8%	0.2%	43.8%	23.8%	15.2%	0.1%	14.6%	0.0%	56.6%	16.6%	12.2%	0.0%
Jul	0.0%	0.3%	56.4%	25.4%	17.7%	0.2%	13.9%	0.1%	52.7%	19.8%	13.5%	0.0%
Aug	0.0%	0.3%	58.5%	23.0%	18.2%	0.2%	18.3%	0.1%	40.4%	23.9%	17.3%	0.0%
Sep	0.0%	0.6%	58.5%	22.8%	18.1%	0.0%	16.9%	0.2%	40.2%	22.1%	20.7%	0.0%
Oct	0.0%	0.3%	53.0%	23.8%	22.9%	0.0%						
Nov	0.0%	0.4%	60.5%	22.0%	17.1%	0.0%						
Dec	0.0%	0.6%	67.9%	20.4%	11.0%	0.1%						
Annual	9.5%	0.3%	48.1%	23.0%	19.0%	0.1%	13.3%	0.2%	53.8%	18.0%	14.7%	0.1%

66 The dispatch run marginal resource and sensitivity factor data is used to calculate the results in the day-ahead market for January 2022 through September 2023 due to the inaccuracy of the sensitivity factor data in the pricing run even though PJM uses LMPs generated in the pricing run as settlement LMPs.

Figure 3-20 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month from 2005 through September 2023. The volume of submitted and cleared up to congestion bids was greater than any point since 2018, when the number of biddable locations for up to congestion transactions was reduced, and before uplift charges for up to congestion transactions took effect on November 1, 2020. The volume of UTCs peaked in April 2023 but decreased significantly from May through September 2023.

Figure 3-20 Monthly bid and cleared INCs, DECs and UTCs (GWh): January 2005 through September 2023

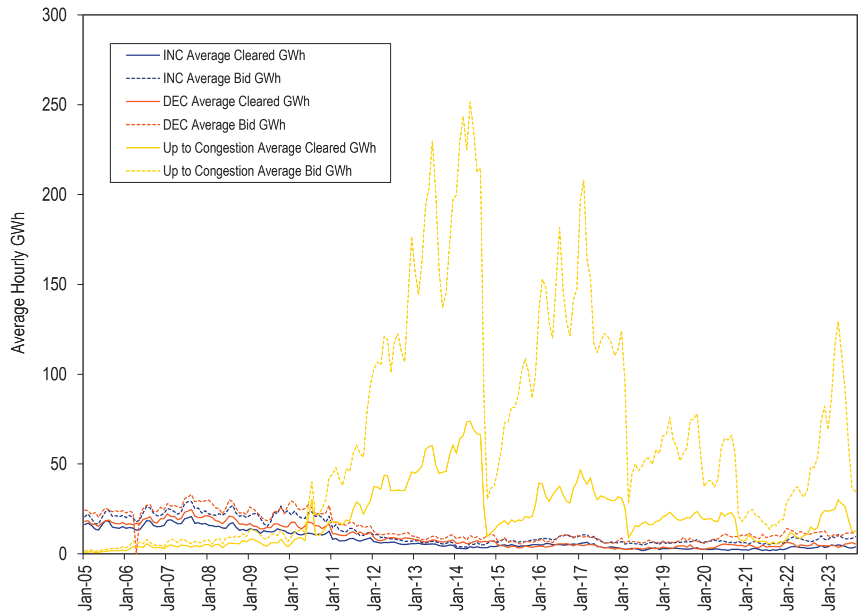
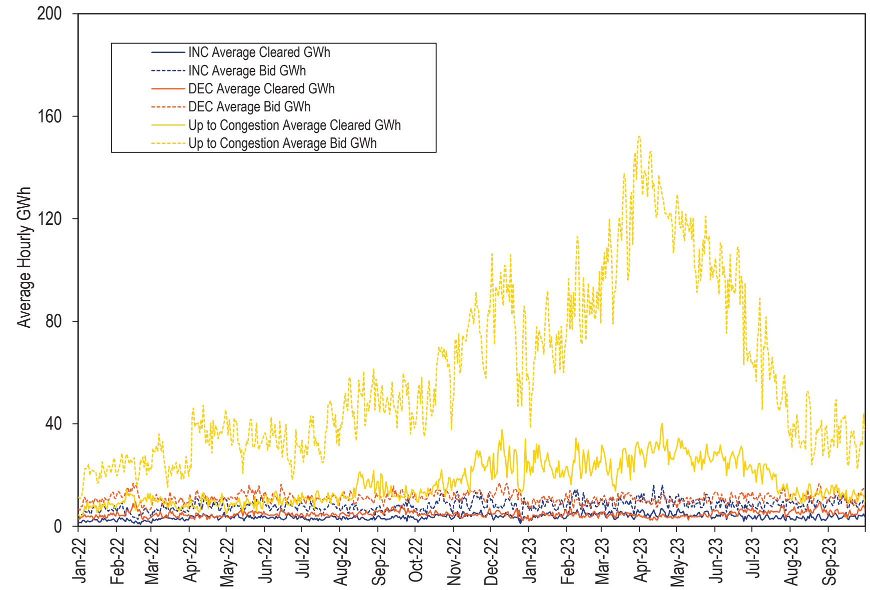


Figure 3-21 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 2022 through September 2023. During this period, the volume of bid and cleared up to congestion transactions increased significantly with a peak in April and then declined significantly.

Figure 3-21 Daily bid and cleared INCs, DECs, and UTCs (GWh): January 2022 through September 2023



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 that primarily take physical positions in PJM markets. Financial entities include banks and hedge funds that 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. Financial entities' share of submitted and cleared MWh of INCs and DECs in the first nine months of 2023 was slightly lower than in the first nine months of 2022, but still made up the majority of all INCs and DECs.

Table 3-24 shows, in the first nine months of 2022 and 2023, the total increment offers and decrement bids and cleared MW by type of parent organization.

Table 3-24 INC and DEC bids and cleared MWh by type of parent organization (MWh): January through September, 2022 and 2023

	2022 (Jan-Sep)				2023 (Jan-Sep)			
Category	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	120,399,637	92.1%	49,331,687	86.6%	118,550,134	91.3%	50,710,178	85.0%
Physical	10,386,777	7.9%	7,655,730	13.4%	11,289,620	8.7%	8,932,348	15.0%
Total	130,786,414	100.0%	56,987,417	100.0%	129,839,754	100.0%	59,642,526	100.0%

Table 3-25 shows, in the first nine months of 2022 and 2023, the total up to congestion bid and cleared MWh by type of parent organization. Up to congestion bids submitted by financial entities more than doubled in the first nine months of 2023 compared the first nine months of 2022, from 231 million MWh to 531 million MWh, while up to congestion bids submitted by physical entities decreased. Financial entities submitted 99.6 percent of all up to congestion bids, up from 95.8 percent, and 99.0 percent of all cleared up to congestion bids, up from 92.5 percent. In the first nine months of 2023, almost all up to congestion trading activity was by financial participants.

Table 3-25 Up to congestion transactions by type of parent organization (MWh): January through September, 2022 and 2023

	2022 (Jan-Sep)				2023 (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	230,599,487	95.8%	66,092,161	92.5%	530,778,913	99.6%	144,605,691	99.0%
Physical	10,049,927	4.2%	5,343,190	7.5%	2,215,070	0.4%	1,432,045	1.0%
Total	240,649,414	100.0%	71,435,351	100.0%	532,993,983	100.0%	146,037,737	100.0%

Table 3-26 shows, in the first nine months of 2022 and 2023, the total import and export transactions by whether the parent organization was financial or physical. The majority of import and export transactions in both day ahead and real time were submitted by physical entities in the first nine months of 2023.

Table 3-26 Import and export transactions by type of parent organization (MWh): January through September, 2022 and 2023

		2022 (Jan-Sep)		2023 (Jan-Sep)	
	Category	Total Import and Export MWh	Percent	Total Import and Export MWh	Percent
Day-Ahead	Financial	7,781,357	31.5%	8,774,894	31.6%
	Physical	16,890,145	68.5%	19,017,996	68.4%
	Total	24,671,502	100.0%	27,792,890	100.0%
Real-Time	Financial	12,254,034	25.5%	13,399,102	25.6%
	Physical	35,888,281	74.5%	38,952,830	74.4%
	Total	48,142,315	100.0%	52,351,932	100.0%

Table 3-27 shows the top 10 locations by total cleared INC and DEC MWh in the first nine months of 2022 and 2023. The top 10 locations included four hubs, four interface pricing points, and two residual metered load aggregates.

Table 3-27 Virtual offers and bids by top 10 locations (MWh): January through September, 2022 and 2023

2022 (Jan-Sep)					2023 (Jan-Sep)				
Aggregate/Bus Name	Aggregate/Bus Type	INC MWh	DEC MWh	Total MWh	Aggregate/Bus Name	Aggregate/Bus Type	INC MWh	DEC MWh	Total MWh
MISO	INTERFACE	109,422	5,378,644	5,488,066	MISO	INTERFACE	199,669	6,989,503	7,189,172
WESTERN HUB	HUB	1,348,456	4,003,340	5,351,797	WESTERN HUB	HUB	2,864,906	1,779,767	4,644,673
SOUTH	INTERFACE	969,099	1,149,934	2,119,033	SOUTH	INTERFACE	2,227,208	417,391	2,644,599
AEP-DAYTON HUB	HUB	511,868	1,311,066	1,822,935	N ILLINOIS HUB	HUB	1,360,307	569,489	1,929,796
NYIS	INTERFACE	665,531	1,080,592	1,746,123	DOM_RESID_AGG	RESIDUAL METERED EDC	166,200	1,679,016	1,845,217
LINDENVFT	INTERFACE	21,785	1,715,993	1,737,777	NYIS	INTERFACE	489,235	1,091,100	1,580,335
N ILLINOIS HUB	HUB	943,107	739,791	1,682,897	LINDENVFT	INTERFACE	28,214	1,394,569	1,422,783
DOM_RESID_AGG	RESIDUAL METERED EDC	77,026	1,605,408	1,682,434	AEP-DAYTON HUB	HUB	549,358	679,928	1,229,286
NEW JERSEY HUB	HUB	812,284	645,670	1,457,955	BGE_RESID_AGG	RESIDUAL METERED EDC	335,997	758,323	1,094,320
CHICAGO GEN HUB	HUB	863,426	428,419	1,291,845	EASTERN HUB	HUB	205,533	553,439	758,972
Top ten total		6,322,004	18,058,857	24,380,862			8,426,627	15,912,525	24,339,152
PJM total		22,682,963	34,304,453	56,987,417			27,413,696	32,228,831	59,642,526
Top ten total as percent of PJM total		27.9%	52.6%	42.8%			30.7%	49.4%	40.8%

Table 3-28 shows up to congestion transactions for the top 10 source and sink pairs and associated source, sink and overall profits on each path in the first nine months of 2022 and 2023. Total profits for up to congestion transactions in the first nine months of 2023 were $34.6 million, a decrease of 69.1 percent compared to profits of $111.8 million in the first nine months of 2022.[67] The UTCs from DOMINION HUB to DOM RESID AGG constituted 65.3 percent of all UTC profits in the first nine months of 2023. Congestion in the Dominion Zone in the first six months of 2023 resulted from the continuing increase in data center load in Northern Virginia. The increase in UTCs on this path alone, which made up more than 22.4 percent of all cleared UTC MW, was a major contributor to the overall increase in UTC volumes in 2022 and the first six months of 2023. The DOMINION HUB to DOM RESID AGG path volumes and profits were higher in the first nine months of 2023 compared to the first nine months of 2022, but the third quarter 2023 volume was approximately 10 million MWh less than in the second quarter and profitability was a net negative $2 million for the third quarter only.

67 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 3-28 Cleared up to congestion bids by top 10 source and sink pairs (MWh): January through September, 2022 and 2023[68]

2022 (Jan-Sep)							
Top 10 Paths by Cleared MWh							
Source	Source Type	Sink	Sink Type	Cleared MW	Source Revenue	Sink Revenue	UTC Profit
DOMINION HUB	HUB	DOM_RESID_AGG	AGGREGATE	3,882,469	$7,979,274	$10,234,119	$15,710,151
CHICAGO GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	2,463,635	$2,780,522	$414,449	$2,181,923
MISO	INTERFACE	SOUTH	INTERFACE	1,854,657	$5,016,211	($35,062)	$3,805,619
CHICAGO GEN HUB	HUB	OHIO HUB	HUB	1,498,160	$4,417,207	($1,302,029)	$2,410,621
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	1,251,972	$5,510,940	($3,574,381)	$1,308,249
CHICAGO HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	1,141,751	$873,915	$322,076	$697,045
MISO	INTERFACE	DEOK_RESID_AGG	AGGREGATE	907,069	$2,307,500	($986,705)	$1,065,155
CHICAGO HUB	HUB	OHIO HUB	HUB	877,089	($845,112)	$2,738,719	$1,554,455
ATSI GEN HUB	HUB	OVEC_RESID_AGG	AGGREGATE	876,452	$1,177,719	($364,285)	$556,535
WESTERN HUB	HUB	DOMINION HUB	HUB	860,457	$3,867,936	($2,221,169)	$1,475,548
Top ten total				15,613,711	$33,086,112	$5,225,732	$30,765,301
PJM total				175,272,518	$119,910,808	$24,499,824	$111,835,446
Top ten total as percent of PJM total				8.9%	27.6%	21.3%	27.5%
2023 (Jan-Sep)							
Top 10 Paths by Cleared MWh							
Source	Source Type	Sink	Sink Type	Cleared MWh	Source Revenue	Sink Revenue	UTC Profit
DOMINION HUB	HUB	DOM_RESID_AGG	AGGREGATE	32,680,354	$29,218,894	($35,092)	$22,606,851
AEP GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	4,394,117	$2,878,107	($1,114,752)	$907,816
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	3,979,757	$3,846,478	($1,134,031)	$1,914,419
CHICAGO GEN HUB	HUB	MISO	INTERFACE	2,825,824	$2,906,108	($2,213,706)	$163,453
CHICAGO GEN HUB	HUB	CHICAGO HUB	HUB	2,503,382	$2,678,217	($2,328,830)	($50,270)
COMED_RESID_AGG	AGGREGATE	AEPIM_RESID_AGG	AGGREGATE	2,144,332	$1,870,262	($1,054,301)	$483,759
CHICAGO GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	1,860,617	$1,536,572	$84,073	$1,160,729
APS_RESID_AGG	AGGREGATE	DOM_RESID_AGG	AGGREGATE	1,672,784	$2,483,483	($1,038,253)	$1,107,782
AEP GEN HUB	HUB	DOM_RESID_AGG	AGGREGATE	1,479,087	$1,652,942	($295,913)	$1,012,625
AEP GEN HUB	HUB	DEOK_RESID_AGG	AGGREGATE	1,456,711	$1,884,847	($1,814,555)	($156,515)
Top ten total				54,996,964	$50,955,909	($10,945,361)	$29,150,650
PJM total				146,037,737	$165,475,180	($101,594,444)	$34,598,761
Top ten total as percent of PJM total				37.7%	30.8%	10.8%	84.3%

68 The columns "Source Revenue" and "Sink Revenue" are totals before uplift charges are subtracted. The column "UTC Profit" includes uplift charges, in addition to the source and sink revenue, and so is less than the sum of the revenue from each side of the transaction.

Table 3-29 shows the average daily number of source-sink pairs that were offered and cleared each month from January 2022 through September 2023. The average number of submitted source-sink pairs per day increased from 1,504 source-sink pairs submitted in 2022 to 1,732 in the first nine months of 2023. The average number of cleared source-sink pairs per day increased from 1,271 in 2022 to 1,339 per day in the first nine months of 2023. The number of pairs traded increased, while the volume of MWh bid and cleared decreased, meaning there was decreasing concentration of trades by path.

Table 3-29 Number of offered and cleared source and sink pairs: January 2022 through September 2023

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2022	Jan	1,398	1,555	1,228	1,405
2022	Feb	1,501	1,633	1,296	1,488
2022	Mar	1,392	1,609	1,178	1,449
2022	Apr	1,415	1,513	1,174	1,274
2022	May	1,417	1,525	1,181	1,291
2022	Jun	1,488	1,644	1,253	1,458
2022	Jul	1,551	1,703	1,305	1,478
2022	Aug	1,689	1,782	1,394	1,521
2022	Sep	1,686	1,855	1,436	1,646
2022	Oct	1,625	1,884	1,336	1,638
2022	Nov	1,552	1,754	1,301	1,497
2022	Dec	1,549	1,822	1,302	1,619
2022	Annual	1,522	1,690	1,282	1,480
2023	Jan	1,558	1,723	1,239	1,480
2023	Feb	1,705	1,812	1,326	1,522
2023	Mar	1,803	1,922	1,318	1,561
2023	Apr	1,756	1,909	1,327	1,550
2023	May	1,729	1,930	1,321	1,646
2023	Jun	1,820	1,886	1,416	1,607
2023	Jul	1,857	1,959	1,475	1,643
2023	Aug	1,748	1,907	1,372	1,657
2023	Sep	1,607	1,853	1,251	1,605
2023	Jan-Sep	1,732	1,878	1,338	1,586

Table 3-30 and Figure 3-22 show total cleared up to congestion transactions and the share of the top 10 up to congestion paths by transaction type (import, export, or internal) in the first nine months of 2022 and 2023. Total cleared up to congestion transactions increased by 104 percent from 71.4 million MWh in the first nine months of 2022 to 146.0 million MWh in the first nine months of 2023. Internal up to congestion transactions in the first nine months of 2023 were 85.1 percent of all up to congestion transactions, an increase from 76.4 percent in the first nine months of 2022.

Table 3-30 Cleared up to congestion transactions and share of top 10 paths by type (MW): January through September, 2022 and 2023

	Import	Export	Wheel	Internal	Total
			2022 (Jan-Sep)		
			Cleared Up to Congestion Bids		
Top ten total (MW)	4,785,703	3,389,921	2,489,480	14,552,996	25,218,101
PJM total (MW)	7,529,620	6,710,156	2,607,480	54,588,096	71,435,351
Top ten total as percent of PJM total	63.6%	50.5%	95.5%	26.7%	35.3%
PJM total as percent of all up to congestion transactions	10.5%	9.4%	3.7%	76.4%	100.0%
			2023 (Jan-Sep)		
			Cleared Up to Congestion Bids		
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	5,019,563	6,662,351	1,883,950	53,617,689	67,183,553
PJM total (MW)	8,359,555	11,370,955	2,098,012	124,209,215	146,037,737
Top ten total as percent of PJM total	60.0%	58.6%	89.8%	43.2%	46.0%
PJM total as percent of all up to congestion transactions	5.7%	7.8%	1.4%	85.1%	100.0%

Figure 3-22 shows the total volume of import, export, wheel, and internal up to congestion transactions by month from January 2005 through September 2023. An initial increase and continued increase in internal up to congestion transactions by month followed 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.[69] 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. In 2018, total UTC activity and 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.[70] The order limited UTC trading to hubs, residual metered load, and interfaces. UTC activity increased following that reduction.

UTC activity decreased again beginning November 1, 2020, after a FERC order requiring UTCs to pay day-ahead and balancing operating reserve charges equivalent to a DEC at the UTC sink point became effective on that date.[71] In 2022 and the first six months of 2023, the volume of cleared UTCs increased significantly, with primarily internal transactions. The volume of cleared UTCs decreased in July, August, and September 2023.

69 See 162 FERC ¶ 61,139 (2018).
70 *Id.*
71 See 172 FERC ¶ 61,046 (2020).

Figure 3-22 Monthly cleared up to congestion transactions by type (GWh): January 2005 through September 2023

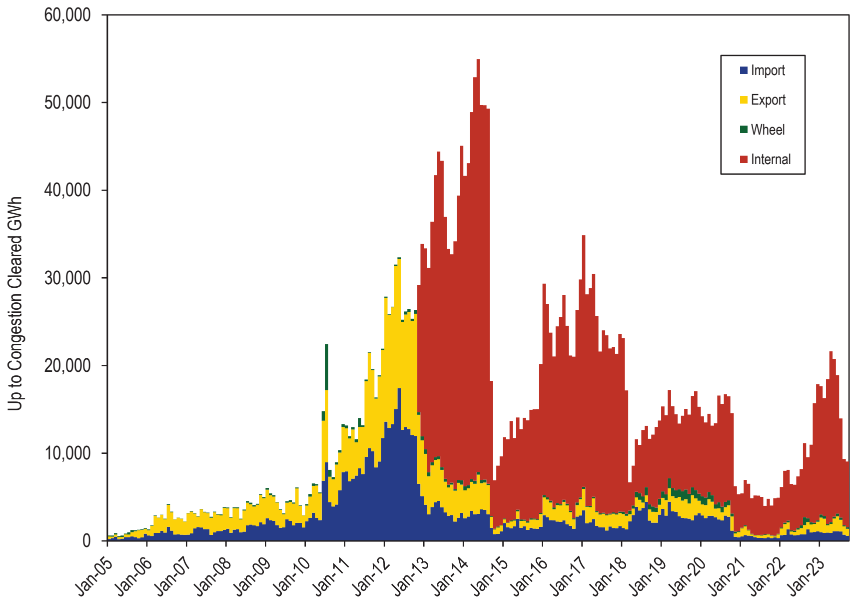
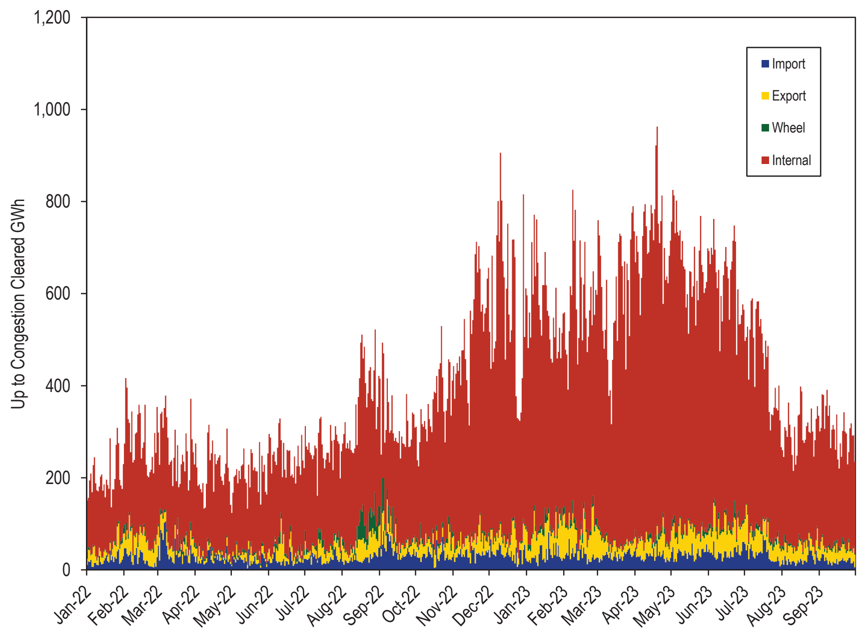


Figure 3-23 shows the daily cleared up to congestion GWh by transaction type from January 1, 2022, through September 30, 2023. In the first nine months of 2023, the total cleared GWh of import and export transactions remained relatively unchanged, while internal up to congestion transactions increased significantly compared to 2022, peaking in April 2023 and decreasing significantly in July, August, and September 2023.

Figure 3-23 Daily cleared up to congestion transaction by type (GWh): January 2022 through September 2023



One of the goals of the February 2018 FERC order accepting PJM's proposal limiting UTC bidding to hubs, interfaces and residual aggregate metered load nodes, and limiting INC and DEC bidding to the same nodes plus active generation nodes, was to limit the opportunities for traders to profit from opportunities for false arbitrage in which price spreads between the day-ahead and real-time energy markets result from differences in the models used to operate each market that cannot be corrected through virtual bidding.[72]

A key assumption underlying the February 2018 order is that the limited set of nodes available for virtual trading is sufficiently protected from false arbitrage trades because price spreads resulting from modeling differences between the day-ahead and real-time markets are mitigated by the averaging of prices over a large number of buses at aggregate nodes.[73] This assumption is not correct, given the large share of INC, DEC, and UTC profits still attributable to modeling or operational differences between day-ahead and real-time since the February 2018 order.

The assumption that modeling differences are averaged out over aggregate nodes does not hold for multiple nodes in the current list of available up to congestion bidding nodes. The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. For example, the MMU recommends eliminating UTC bidding at the following pricing points: DPLEASTON_RESID_AGG, PENNPOWER_RESID_AGG, UGI_RESID_AGG, SMECO_RESID_AGG, AEPKY_RESID_AGG, and VINELAND_RESID_AGG.

Prices at larger aggregate nodes can also be affected by transmission constraints, especially when constraints are violated and transmission penalty factors are applied in the real-time energy market. Even when the same constraints are modeled in day ahead and real time, constraint violations in real time may result from differences in the day-ahead and real-time operational environments such as intra hourly ramping limitations, changes to constraint limits, and unit commitments and decommitments. Price spreads due to modeling or operational differences can be in the tens to hundreds of dollars, even when averaged over an aggregate node, and may persist for days or weeks. Virtual traders can often identify and profit from price spreads

72 PJM Interconnection, LLC, "Proposed Revisions To Reduce Bidding Points for Virtual Transactions," Docket No. ER18-88, October 17, 2017 at 9–10: "Discrepancies between the models can occur for various reasons despite PJM's best attempts to minimize them…Because individual nodes are more highly impacted by modeling discrepancies than aggregated locations due to averaging, they are often locations where Virtual Transactions can profit. Profits collected by Virtual Transactions in these cases lead to additional costs for PJM members without any benefits."

73 162 FERC ¶ 61,139 at PP 35–36 (2018) ("We accept PJM's proposal to limit eligible bidding points for UTCs to hubs, residual metered load, and interfaces. First, we agree with the IMM's statement that PJM's proposal to limit the UTC bid locations to interfaces, zones, and hubs will minimize false arbitrage opportunities for UTCs currently being pursued through penny bids, as the effect of modeling differences between the day-ahead and real-time markets are minimized at these aggregates.").

resulting from systematic modeling and operational differences between day-ahead and real-time affecting specific generators or aggregate nodes. The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues.

MLSA Market Manipulation Cases

In 2009, PJM proposed rules for calculating the marginal loss surplus allocation (MLSA) that permitted allocations of marginal losses to transactions, including up to congestion transactions, which exceeded the cost of the transmission service required to support such transactions.[74] The MLSA rules were approved on September 17, 2009.[75] The order denying rehearing issued April 15, 2010, providing assurance that the MLSA rules were final.[76] On May 15, 2010 through September 17, some virtual traders engaged in economically meaningless wash trades in order to improperly obtain a share of the MLSA. Because the up to congestion trades offset or nearly offset, such traders received MLSA exceeding the cost of transmission purchased to support the transaction.

On January 6, 2011, the MMU submitted a referral of multiple entities to the FERC Office of Enforcement pursuant to OATT Section IV.I.1 of Attachment M. The referral (made public by Powhatan) detailed the manipulative scheme and recommended investigation.[77] FERC issued a series of show cause orders based on the referral and the Office of Enforcement's investigation. The show cause order resulted in assessments of penalties on virtual traders including Powhatan Energy Fund, LLC, HEEP Fund, Inc., CU Fund, Inc., and Houlian Chen (IN15-3); Coaltrain Energy, L.P., Peter Jones, Shawn Sheehan, Robert Jones, Jeff Miller, and Jack Wells (IN16-4); and City Power Marketing, LLC and K. Stephen Tsingas (IN15-5).[78] A fourth case, Oceanside Power, LLC (Oceanside) and Robert Scavo (IN10-5) was resolved prior to an assessment of penalties.

On July 31, 2015, FERC filed a petition in U.S. District Court for the Eastern District of Virginia to enforce its penalty in the Powhatan case.[79] On October 29, 2021, the Houlian Chen case was resolved separately from the rest of the Powhatan Energy, et al., case through an order approving stipulation and consent, which required Houlian Chen to disgorge $600,000.[80] On March 22, 2023, the rest of the Powhatan court case was substantively resolved by the court's grant of FERC's motion for a default judgment requiring that Powhatan disgorge $3,465,108 and pay a civil penalty of $16,800,000. Because Powhatan filed for bankruptcy on February 26, 2022, and that case remains pending, any payment to FERC will be determined in the bankruptcy proceeding.[81] During the court case, the MMU was subject to a subpoena, including extensive discovery and a deposition. On October 11, 2022, the Coaltrain Energy, L.P., et al., case was resolved through an order approving a stipulation and consent agreement, which provided for Coaltrain to disgorge $4,000,000.[82] The resolution at FERC followed years of litigation by FERC in the U.S. District Court for the Southern District of Ohio seeking to enforce its penalty.[83] The MMU was subject to a subpoena in that proceeding, including a deposition.

On August 22, 2017, the City Power et al. case was resolved through an order approving stipulation and consent agreement, which required Paul Tsingas to disgorge $1,300,000 and pay a penalty of $1,420,000, and City Power pay a civil penalty of $9,000,000.[84]

On February 13, 2013, the Oceanside Power, et al., case was resolved through an order approving a stipulation and consent agreement, which provided for Oceanside to disgorge $29,563 and pay a civil penalty of $51,000.

Over a decade of litigation was required to prevail on a matter that, at its core, involved wash trading, a common manipulative scheme. These cases illustrate the limitations of reliance on ex post enforcement mechanisms to prevent market manipulation, including fraudulent schemes and exercise of market

74 See PJM Compliance Filing, FERC Docket EL08-14-002 (March 26, 2009).
75 See 128 FERC ¶ 61,262.
76 See 131 FERC ¶ 61,024.
77 See website, "FERC vs. Powhatan Energy Fund, LLC: Legal Materials, Independent Expert Opinions and More," which can be accessed at: <https://ferclitigation.com/>.
78 See 151 FERC 61,179 (2015); 155 FERC ¶ 61,204 (2016); and 152 FERC ¶ 61,012 (2015).
79 See Case No. 3:15-cv-0542.
80 See 177 FERC ¶ 61,076.
81 Delaware Bankruptcy Court, Case No. 1:2022bk10142 (filed February 16, 2022).
82 See 181 FERC ¶ 61,031.
83 Case No. 2:16-cv-732-MHW-KAJ.
84 See 160 FERC ¶ 61,013.

power. It is essential to avoid flawed rules in the first instance, and thereby address potential manipulation and exercise of market power ex ante.

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, surrogate constraints for reactive power and generator stability, or influence prices through manual interventions such as load biasing, changing constraint limits and penalty factors, and committing reserves beyond the requirement.

The real-time average LMP in the first nine months of 2023 decreased 59.6 percent from the first nine months of 2022, from $72.57 per MWh to $29.29 per MWh. The real-time load-weighted average LMP in the first nine months of 2023 decreased 60.3 percent from the first nine months of 2022, from $77.84 per MWh to $30.87 per MWh.

The costs of fuel, emissions, and consumables, fundamental components of the real-time load weighted average LMP, decreased $30.57 per MWh from $50.26 per MWh in the first nine months of 2022 to $19.69 per MWh in the first nine months of 2023, which accounts for 65.1 percent of the decrease in real-time load-weighted average LMP.

The day-ahead average LMP for the first nine months of 2023 decreased 58.4 percent from the first nine months of 2022, from $72.36 per MWh to $30.10 per MWh. The day-ahead load-weighted average LMP in the first nine months of 2023 decreased 58.6 percent from the first nine months of 2022, from $76.97 per MWh to $31.90 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.[85] 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.[86]

LMP may, at times, be set by transmission penalty factors, which equal a default level of $30,000 per MWh in the dispatch run in the day-ahead market and $2,000 per MWh in the real-time market and in the day-ahead market pricing run. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, the transmission limits may be violated in the market dispatch solution. 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. But PJM operator interventions to reduce line ratings unnecessarily trigger transmission constraint penalty factors and significantly increase prices. A

85 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.

86 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).

competitive market does not require that prices increase when PJM artificially triggers transmission constraint penalty factors.

Fast Start Pricing: DLMP and PLMP

PJM implemented fast start pricing in both the day-ahead and real-time markets on September 1, 2021. Fast start pricing employs a new LMP calculation called the pricing run. The pricing run LMP (PLMP) is now the official settlement LMP in PJM, replacing the dispatch run LMP (DLMP). Unless otherwise specified, the LMP tables and figures show the PLMP for September 1, 2021, and after.

The pricing run calculates LMP using the same optimal power flow algorithm as the dispatch run while simultaneously ignoring (relaxing) the economic minimum and maximum output MW constraints for all eligible fast start units. Fast start units must have: notification time plus start time are less than or equal to one hour; minimum run time is less than or equal to one hour; and units are online and running for PJM, not self-scheduled.

The goal of fast start pricing is to allow inflexible resources to set prices based on the sum of their commitment costs per MWh and their marginal costs. 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. Units that start in one hour are not actually 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 distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions. PJM is paying new forms of uplift in an attempt to counter the distorted incentives inherent in fast start pricing.

PJM has also introduced other differences between the dispatch run and pricing run that are not related to fast start pricing. For example, in the day-ahead market, PJM uses a default $30,000 per MWh transmission constraint penalty factor in the dispatch run and a $2,000 per MWh transmission constraint penalty factor in the pricing run. Starting on October 1, 2022, PJM uses capping of the system marginal price only in the pricing run, which affected real-time market prices during Winter Storm Elliott in December 2022. This price calculation has not been reviewed by FERC or included in the PJM Operating Agreement. Every difference between the dispatch run and the pricing run introduces inefficiency in the market.

DLMP and PLMP

Table 3-31 shows the day-ahead and real-time monthly load-weighted average PLMP and DLMP for 2022 through September 2023.

The real-time load-weighted average PLMP was $30.87 per MWh for the first nine months of 2023, which is 5.9 percent, $1.73 per MWh, higher than the real-time load-weighted average DLMP of $29.14 per MWh.

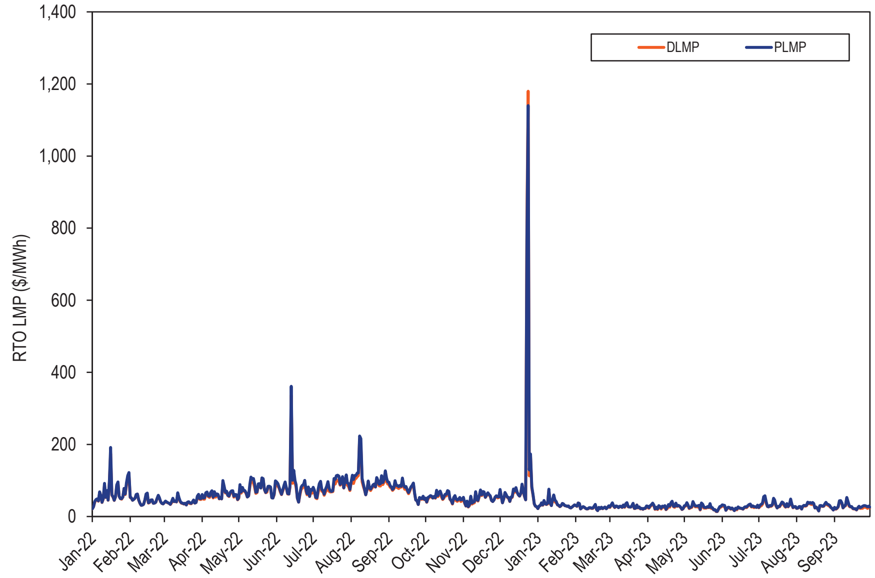
The day-ahead load-weighted average PLMP was $31.90 per MWh for the first nine months of 2023, which is 0.1 percent, $0.04 per MWh, higher than the day-ahead load-weighted average DLMP of $31.86 per MWh.

Table 3-31 Day-ahead and real-time load-weighted average DLMP and PLMP: 2022 through September 2023

		Day-Ahead Load-Weighted Average				Real-Time Load-Weighted Average			
Year	Month	DLMP	PLMP	Difference	Percent Difference	DLMP	PLMP	Difference	Percent Difference
2022	Jan	$64.57	$64.80	$0.22	0.3%	$66.43	$69.06	$2.64	4.0%
2022	Feb	$49.96	$50.35	$0.39	0.8%	$45.93	$46.76	$0.83	1.8%
2022	Mar	$45.25	$45.50	$0.25	0.6%	$41.83	$43.56	$1.73	4.1%
2022	Apr	$64.10	$64.18	$0.08	0.1%	$60.38	$63.91	$3.52	5.8%
2022	May	$83.17	$83.24	$0.06	0.1%	$79.04	$83.16	$4.12	5.2%
2022	Jun	$90.24	$90.54	$0.29	0.3%	$91.44	$97.89	$6.46	7.1%
2022	Jul	$96.07	$96.38	$0.32	0.3%	$84.03	$92.48	$8.45	10.1%
2022	Aug	$106.18	$106.07	($0.10)	(0.1%)	$105.68	$113.74	$8.06	7.6%
2022	Sep	$82.86	$82.80	($0.06)	(0.1%)	$74.08	$78.29	$4.22	5.7%
2022	Oct	$58.30	$58.37	$0.07	0.1%	$52.27	$55.90	$3.63	6.9%
2022	Nov	$56.29	$55.24	($1.05)	(1.9%)	$50.86	$52.93	$2.07	4.1%
2022	Dec	$93.02	$93.39	$0.37	0.4%	$143.65	$142.22	($1.42)	(1.0%)
2022	Jan - Sep	$75.82	$75.99	$0.16	0.2%	$72.09	$76.54	$4.45	6.2%
2022	Jan - Dec	$75.35	$75.44	$0.08	0.1%	$76.34	$80.14	$3.80	5.0%
2023	Jan	$36.53	$36.58	$0.05	0.1%	$34.66	$35.75	$1.09	3.1%
2023	Feb	$31.16	$31.22	$0.06	0.2%	$25.47	$26.04	$0.57	2.2%
2023	Mar	$28.39	$28.41	$0.02	0.1%	$27.58	$28.42	$0.85	3.1%
2023	Apr	$29.81	$29.81	($0.00)	(0.0%)	$27.06	$29.24	$2.19	8.1%
2023	May	$28.86	$28.80	($0.05)	(0.2%)	$25.91	$28.44	$2.53	9.7%
2023	Jun	$27.82	$27.82	($0.00)	(0.0%)	$25.69	$27.29	$1.60	6.2%
2023	Jul	$40.46	$40.56	$0.10	0.3%	$34.34	$37.21	$2.87	8.4%
2023	Aug	$30.49	$30.54	$0.05	0.2%	$29.80	$31.33	$1.53	5.1%
2023	Sep	$30.82	$30.91	$0.09	0.3%	$29.33	$31.55	$2.22	7.6%
2023	Jan - Sep	$31.86	$31.90	$0.04	0.1%	$29.14	$30.87	$1.73	5.9%

Figure 3-24 shows the real-time daily average DLMP and PLMP for 2022 through September 2023. As a result of price capping during Winter Storm Elliott, the real-time daily average DLMP was $1,179.84 per MWh and PLMP was $1,140.07 per MWh on December 24, 2022.

Figure 3-24 Real-time daily average DLMP and PLMP: 2022 through September 2023



Fast start pricing affected the difference between DLMP and PLMP in real time more than in day ahead. Figure 3-25 shows the hourly difference between DLMP and PLMP in day-ahead and real-time for the first nine months of 2023.

Figure 3-25 Hourly difference between DLMP and PLMP for day-ahead and real-time: January through September, 2023

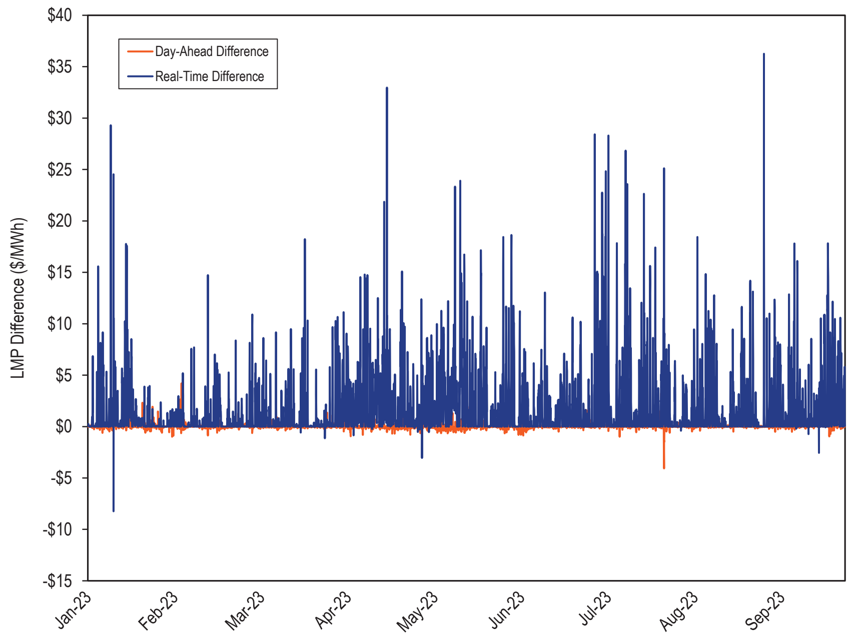


Figure 3-26 shows the hourly average load and LMP difference by hour of the day for the first nine months of 2023.

Figure 3-26 Hourly average load and LMP difference: January through September, 2023

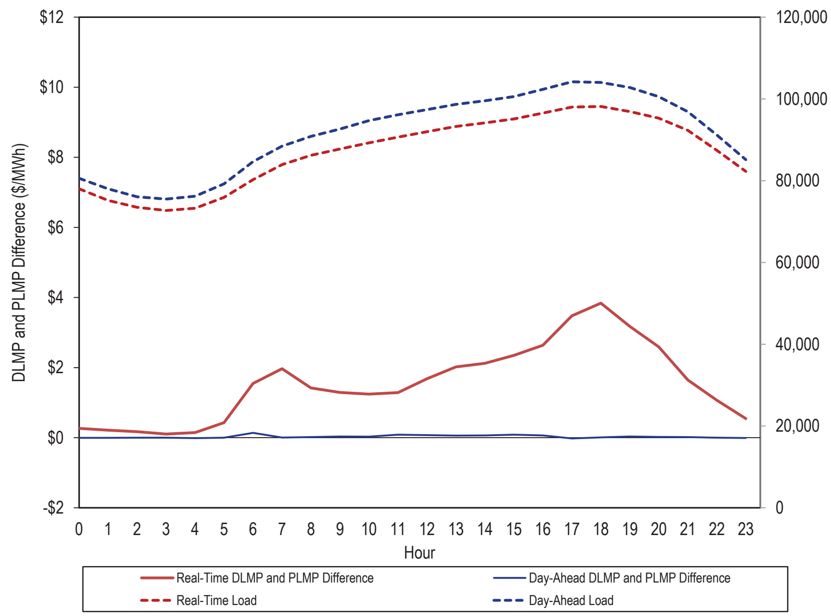


Table 3-32 shows the percent of total marginal units that are fast start units by unit type for 2022 through September 2023. While wind units are defined as fast start units, a wind unit on the margin does not result in a higher PLMP than DLMP when the unit has no commitment costs.

Table 3-32 Fast start units as a percent of real-time marginal units: 2022 through September 2023

		Dispatch Run				Pricing Run			
Year	Month	CT	Diesel	Wind	All Fast Start Units	CT	Diesel	Wind	All Fast Start Units
2022	Jan	1.3%	0.3%	0.2%	1.8%	4.9%	0.9%	0.2%	6.2%
2022	Feb	0.6%	0.2%	0.3%	1.1%	3.2%	0.5%	0.3%	4.0%
2022	Mar	0.5%	0.2%	0.4%	1.1%	3.4%	0.5%	0.4%	4.4%
2022	Apr	0.8%	0.1%	0.1%	1.2%	4.4%	0.3%	0.1%	5.0%
2022	May	1.4%	0.7%	0.1%	2.4%	6.6%	1.2%	0.1%	8.1%
2022	Jun	2.3%	0.3%	0.1%	2.6%	9.3%	0.8%	0.1%	10.2%
2022	Jul	2.7%	0.6%	0.1%	3.3%	16.3%	1.4%	0.0%	17.7%
2022	Aug	2.0%	0.4%	0.0%	2.4%	12.0%	1.3%	0.0%	13.3%
2022	Sep	0.8%	0.3%	0.1%	1.2%	5.6%	1.0%	0.1%	6.7%
2022	Oct	2.2%	0.2%	0.3%	2.6%	6.6%	0.9%	0.2%	7.7%
2022	Nov	1.3%	0.2%	0.2%	1.7%	5.1%	0.9%	0.2%	6.1%
2022	Dec	1.3%	0.7%	0.2%	2.2%	6.3%	1.5%	0.2%	8.0%
2022	Jan - Sep	1.4%	0.3%	0.2%	1.9%	7.3%	0.9%	0.1%	8.4%
2023	Jan	1.6%	0.5%	0.1%	2.1%	6.2%	2.8%	0.0%	9.0%
2023	Feb	0.9%	0.2%	0.0%	1.1%	3.1%	0.6%	0.0%	3.7%
2023	Mar	0.8%	0.4%	0.1%	1.2%	3.0%	0.7%	0.1%	3.8%
2023	Apr	2.5%	0.4%	0.2%	3.2%	8.1%	0.8%	0.2%	9.1%
2023	May	1.0%	0.3%	0.1%	1.3%	4.8%	0.7%	0.1%	5.6%
2023	Jun	0.5%	0.2%	0.0%	0.7%	2.5%	0.5%	0.0%	3.0%
2023	Jul	1.4%	0.9%	0.0%	2.4%	8.6%	1.6%	0.0%	10.3%
2023	Aug	0.9%	1.5%	0.0%	2.4%	5.1%	2.3%	0.0%	7.4%
2023	Sep	0.4%	0.8%	0.1%	1.3%	5.1%	1.4%	0.1%	6.5%
2023	Jan - Sep	1.1%	0.6%	0.1%	1.7%	5.2%	1.3%	0.1%	6.5%

Table 3-33 shows the difference between day-ahead and real-time zonal average DLMP and PLMP for the first nine months of 2023.

Fast start pricing affects some zones more than others. The average difference in real-time prices in DPL was $1.97 per MWh, while the average difference in real-time prices in PECO was $1.02 per MWh.

Table 3-33 Day-ahead and real-time zonal average DLMP and PLMP (Dollars per MWh): January through September, 2023

	2023 (Jan-Sep)							
	Day-Ahead				Real-Time			
Zone	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
ACEC	$24.04	$24.07	$0.02	0.1%	$22.19	$23.27	$1.08	4.9%
AEP	$30.85	$30.89	$0.03	0.1%	$28.22	$29.82	$1.60	5.7%
APS	$31.49	$31.52	$0.03	0.1%	$28.58	$30.22	$1.64	5.7%
ATSI	$30.57	$30.60	$0.04	0.1%	$28.03	$29.60	$1.57	5.6%
BGE	$37.55	$37.58	$0.03	0.1%	$33.48	$35.44	$1.97	5.9%
COMED	$26.77	$26.80	$0.03	0.1%	$24.51	$25.96	$1.45	5.9%
DAY	$32.36	$32.39	$0.04	0.1%	$29.59	$31.28	$1.69	5.7%
DUKE	$31.84	$31.87	$0.04	0.1%	$29.10	$30.75	$1.65	5.7%
DOM	$35.10	$35.12	$0.03	0.1%	$33.06	$34.82	$1.76	5.3%
DPL	$27.20	$27.21	$0.01	0.0%	$25.32	$27.29	$1.97	7.8%
DUQ	$30.16	$30.20	$0.04	0.1%	$27.70	$29.26	$1.57	5.7%
EKPC	$30.96	$30.99	$0.03	0.1%	$28.69	$30.31	$1.62	5.6%
JCPLC	$24.62	$24.64	$0.02	0.1%	$22.76	$23.90	$1.14	5.0%
MEC	$26.59	$26.62	$0.03	0.1%	$24.34	$25.70	$1.36	5.6%
OVEC	$30.34	$30.37	$0.03	0.1%	$27.98	$29.57	$1.58	5.7%
PECO	$23.17	$23.19	$0.02	0.1%	$21.46	$22.48	$1.02	4.8%
PE	$29.39	$29.39	$0.00	0.0%	$27.10	$28.57	$1.47	5.4%
PEPCO	$35.78	$35.81	$0.03	0.1%	$31.89	$33.73	$1.84	5.8%
PPL	$24.62	$24.64	$0.03	0.1%	$22.60	$23.81	$1.21	5.3%
PSEG	$24.87	$24.89	$0.02	0.1%	$23.01	$24.14	$1.14	4.9%
REC	$26.61	$26.63	$0.02	0.1%	$24.75	$25.94	$1.19	4.8%

Table 3-34 shows the difference between day-ahead and real-time average DLMP and PLMP for PJM hubs for the first nine months of 2023.

The average difference in real-time prices for EASTERN HUB was $1.90 per MWh, while the average difference in real-time prices for NEW JERSEY HUB was $1.13 per MWh.

Table 3-34 Day-ahead and real-time average DLMP and PLMP for PJM hubs (Dollars per MWh): January through September, 2023

	2023 (Jan-Sep)							
	Day-Ahead				Real-Time			
Hub	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
AEP GEN HUB	$29.96	$30.00	$0.03	0.1%	$27.47	$29.03	$1.55	5.6%
AEP-DAYTON HUB	$30.61	$30.64	$0.03	0.1%	$28.01	$29.60	$1.59	5.7%
ATSI GEN HUB	$29.96	$30.00	$0.03	0.1%	$27.41	$28.96	$1.55	5.7%
CHICAGO GEN HUB	$26.32	$26.35	$0.03	0.1%	$24.02	$25.47	$1.44	6.0%
CHICAGO HUB	$26.87	$26.90	$0.03	0.1%	$24.48	$25.92	$1.44	5.9%
DOMINION HUB	$33.28	$33.31	$0.03	0.1%	$30.49	$32.18	$1.70	5.6%
EASTERN HUB	$27.40	$27.41	$0.00	0.0%	$25.27	$27.16	$1.90	7.5%
N ILLINOIS HUB	$26.74	$26.77	$0.03	0.1%	$24.55	$26.01	$1.46	5.9%
NEW JERSEY HUB	$24.61	$24.64	$0.02	0.1%	$22.75	$23.88	$1.13	5.0%
OHIO HUB	$30.57	$30.61	$0.03	0.1%	$27.98	$29.57	$1.59	5.7%
WEST INT HUB	$31.25	$31.29	$0.03	0.1%	$28.56	$30.17	$1.61	5.6%
WESTERN HUB	$31.96	$31.97	$0.01	0.0%	$28.88	$30.53	$1.65	5.7%

Table 3-35 shows the frequency of the real-time pricing interval differences in DLMP and PLMP by price range for PJM zones for the first nine months of 2023.

Table 3-35 Real-time interval difference (dollars per MWh) between zonal DLMP and PLMP: January through September, 2023

	2023 (Jan-Sep)									
Zone	< ($50)	($50) to ($10)	($10) to $0	$0	$0 to $10	$10 to $20	$20 to $50	$50 to $100	$100 to $200	>= $200
PJM-RTO	0.0%	0.0%	0.6%	47.4%	48.5%	2.8%	0.6%	0.0%	0.0%	0.0%
AECO	0.0%	0.0%	7.5%	48.0%	41.9%	2.0%	0.5%	0.0%	0.0%	0.0%
AEP	0.0%	0.0%	1.0%	47.9%	47.4%	3.0%	0.6%	0.0%	0.0%	0.0%
APS	0.0%	0.0%	0.8%	47.7%	47.7%	3.0%	0.7%	0.1%	0.0%	0.0%
ATSI	0.0%	0.0%	1.0%	47.6%	47.9%	2.9%	0.6%	0.0%	0.0%	0.0%
BGE	0.0%	0.0%	3.8%	47.3%	43.4%	3.9%	1.3%	0.1%	0.0%	0.0%
COMED	0.0%	0.1%	2.6%	48.2%	45.8%	2.7%	0.6%	0.0%	0.0%	0.0%
DAY	0.0%	0.0%	1.0%	47.8%	47.2%	3.3%	0.7%	0.1%	0.0%	0.0%
DEOK	0.0%	0.0%	1.1%	47.8%	47.2%	3.2%	0.7%	0.1%	0.0%	0.0%
DOM	0.0%	0.1%	2.3%	47.6%	45.4%	3.4%	1.0%	0.1%	0.0%	0.0%
DPL	0.0%	0.0%	11.7%	47.9%	37.1%	1.9%	0.5%	0.2%	0.6%	0.0%
DUQ	0.0%	0.0%	0.8%	47.6%	48.1%	2.9%	0.6%	0.0%	0.0%	0.0%
EKPC	0.0%	0.0%	1.1%	47.8%	47.3%	3.1%	0.6%	0.0%	0.0%	0.0%
JCPL	0.0%	0.0%	3.4%	47.9%	46.1%	2.0%	0.5%	0.0%	0.0%	0.0%
METED	0.0%	0.0%	3.9%	47.5%	45.5%	2.5%	0.6%	0.1%	0.0%	0.0%
OVEC	0.0%	0.0%	1.2%	47.9%	47.3%	3.0%	0.6%	0.0%	0.0%	0.0%
PECO	0.0%	0.0%	10.3%	48.0%	39.2%	2.0%	0.5%	0.0%	0.0%	0.0%
PENELEC	0.0%	0.0%	1.4%	47.3%	48.1%	2.6%	0.6%	0.1%	0.0%	0.0%
PEPCO	0.0%	0.0%	2.8%	47.6%	44.8%	3.6%	1.1%	0.1%	0.0%	0.0%
PPL	0.0%	0.0%	4.2%	47.5%	45.7%	2.1%	0.5%	0.0%	0.0%	0.0%
PSEG	0.0%	0.0%	3.3%	47.9%	46.3%	2.0%	0.4%	0.0%	0.0%	0.0%
RECO	0.0%	0.0%	2.8%	47.6%	46.9%	2.1%	0.5%	0.0%	0.0%	0.0%

Real-Time Average LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[87]

PJM Real-Time Average LMP

Table 3-36 shows the real-time average LMP for the first nine months of 1998 through 2023.[88] The real-time average LMP in the first nine months of 2023 decreased $43.28 per MWh, or 59.6 percent from 2022, from $72.57 per MWh to $29.29 per MWh.

Table 3-36 Real-time average LMP (Dollars per MWh): January through September, 1998 through 2023

	Real-Time LMP			Year to Year Change			
Jan-Sep	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
1998	$23.18	$16.86	$36.00	NA	NA	NA	NA
1999	$31.65	$18.77	$83.28	$8.47	36.6%	11.3%	131.3%
2000	$25.88	$18.22	$23.70	($5.77)	(18.2%)	(2.9%)	(71.5%)
2001	$36.00	$25.48	$51.30	$10.12	39.1%	39.9%	116.4%
2002	$28.13	$20.70	$23.92	($7.88)	(21.9%)	(18.8%)	(53.4%)
2003	$40.42	$33.68	$26.00	$12.30	43.7%	62.7%	8.7%
2004	$43.85	$39.99	$21.82	$3.43	8.5%	18.7%	(16.1%)
2005	$54.69	$44.53	$33.67	$10.83	24.7%	11.4%	54.3%
2006	$51.79	$43.50	$34.93	($2.90)	(5.3%)	(2.3%)	3.7%
2007	$57.34	$49.40	$35.52	$5.55	10.7%	13.6%	1.7%
2008	$71.94	$61.33	$41.64	$14.59	25.4%	24.2%	17.2%
2009	$37.42	$33.00	$17.92	($34.51)	(48.0%)	(46.2%)	(57.0%)
2010	$46.13	$37.89	$26.99	$8.70	23.3%	14.8%	50.6%
2011	$45.79	$37.05	$32.25	($0.33)	(0.7%)	(2.2%)	19.5%
2012	$32.45	$28.78	$21.94	($13.34)	(29.1%)	(22.3%)	(32.0%)
2013	$37.30	$32.44	$22.84	$4.85	15.0%	12.7%	4.1%
2014	$52.72	$36.06	$74.17	$15.42	41.3%	11.2%	224.8%
2015	$35.96	$27.88	$30.75	($16.76)	(31.8%)	(22.7%)	(58.5%)
2016	$27.43	$23.61	$15.73	($8.53)	(23.7%)	(15.3%)	(48.8%)
2017	$28.79	$25.28	$16.81	$1.36	5.0%	7.1%	6.9%
2018	$36.52	$27.26	$33.22	$7.73	26.8%	7.8%	97.6%
2019	$26.30	$23.39	$17.69	($10.22)	(28.0%)	(14.2%)	(46.8%)
2020	$19.95	$17.87	$10.48	($6.34)	(24.1%)	(23.6%)	(40.7%)
2021	$33.49	$26.82	$24.08	$13.54	67.9%	50.1%	129.8%
2022	$72.57	$59.66	$59.73	$39.08	116.7%	122.4%	148.0%
2023	$29.29	$25.57	$18.21	($43.28)	(59.6%)	(57.1%)	(69.5%)

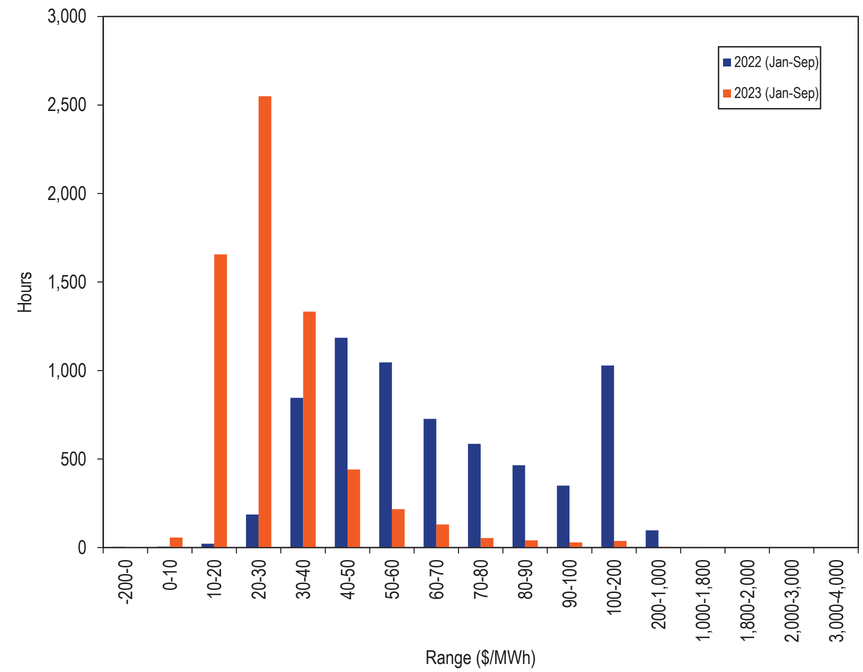
87 See the *Technical Reference for PJM Markets*, at "Calculating Locational Marginal Price," p 16-18 for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

88 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 3-27 shows the hourly distribution of the real-time average LMP during the first nine months of 2022 and 2023. In the first nine months of 2022, the most common price range was $40 to $50 per MWh. In the first nine months of 2023, the most common price range was $20 to $30 per MWh.

Figure 3-27 Distribution of real-time LMP: January through September, 2022 and 2023



Real-Time Load-Weighted Average LMP

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

PJM Real-Time Load-Weighted Average LMP

Table 3-37 shows the real-time load-weighted average LMP for the first nine months of 1998 through 2023. The real-time load-weighted average LMP in the first nine months of 2023 decreased $46.97 per MWh, or 60.3 percent from the first nine months of 2022, from $77.84 per MWh to $30.87 per MWh. This is the largest dollar and percent decrease in PJM real-time load-weighted average LMP for the first three quarters of the year since competitive markets were introduced in 1999.

Table 3-37 Real-time load-weighted average LMP (Dollars per MWh): January through September, 1998 through 2023

	Real-Time Load-Weighted Average LMP			Year to Year Change			
Jan-Sep	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
1998	$26.06	$18.20	$44.65	NA	NA	NA	NA
1999	$38.65	$20.02	$104.17	$12.59	48.3%	10.0%	133.3%
2000	$28.49	$19.30	$26.89	($10.16)	(26.3%)	(3.6%)	(74.2%)
2001	$40.96	$28.18	$64.57	$12.47	43.8%	46.0%	140.1%
2002	$31.95	$23.09	$29.14	($9.01)	(22.0%)	(18.1%)	(54.9%)
2003	$43.57	$38.17	$26.53	$11.61	36.3%	65.3%	(9.0%)
2004	$46.44	$43.03	$21.89	$2.87	6.6%	12.7%	(17.5%)
2005	$60.44	$50.10	$36.52	$14.01	30.2%	16.4%	66.9%
2006	$56.39	$46.82	$40.70	($4.06)	(6.7%)	(6.5%)	11.4%
2007	$61.83	$55.12	$37.98	$5.45	9.7%	17.7%	(6.7%)
2008	$77.27	$66.73	$43.80	$15.43	25.0%	21.1%	15.3%
2009	$39.57	$34.57	$19.04	($37.70)	(48.8%)	(48.2%)	(56.5%)
2010	$49.91	$40.33	$29.65	$10.35	26.2%	16.7%	55.7%
2011	$49.48	$38.72	$37.02	($0.44)	(0.9%)	(4.0%)	24.8%
2012	$35.02	$29.84	$25.44	($14.46)	(29.2%)	(22.9%)	(31.3%)
2013	$39.75	$33.61	$26.47	$4.72	13.5%	12.6%	4.0%
2014	$58.60	$37.93	$86.22	$18.86	47.4%	12.8%	225.8%
2015	$38.94	$29.09	$33.95	($19.66)	(33.5%)	(23.3%)	(60.6%)
2016	$29.32	$24.60	$17.13	($9.62)	(24.7%)	(15.4%)	(49.6%)
2017	$30.36	$26.26	$18.81	$1.04	3.5%	6.7%	9.8%
2018	$39.43	$28.78	$36.82	$9.08	29.9%	9.6%	95.7%
2019	$27.60	$24.23	$18.69	($11.83)	(30.0%)	(15.8%)	(49.2%)
2020	$21.22	$18.66	$11.53	($6.38)	(23.1%)	(23.0%)	(38.3%)
2021	$35.68	$28.41	$26.03	$14.46	68.1%	52.3%	125.8%
2022	$77.84	$63.39	$68.59	$42.16	118.2%	123.1%	163.5%
2023	$30.87	$26.77	$19.69	($46.97)	(60.3%)	(57.8%)	(71.3%)

PJM Real-Time Monthly Load-Weighted Average LMP

Figure 3-28 shows the real-time monthly and yearly load-weighted average LMP for January 1999 through September 2023.

Figure 3-28 Real-time monthly and yearly load-weighted average LMP: 1999 through September 2023

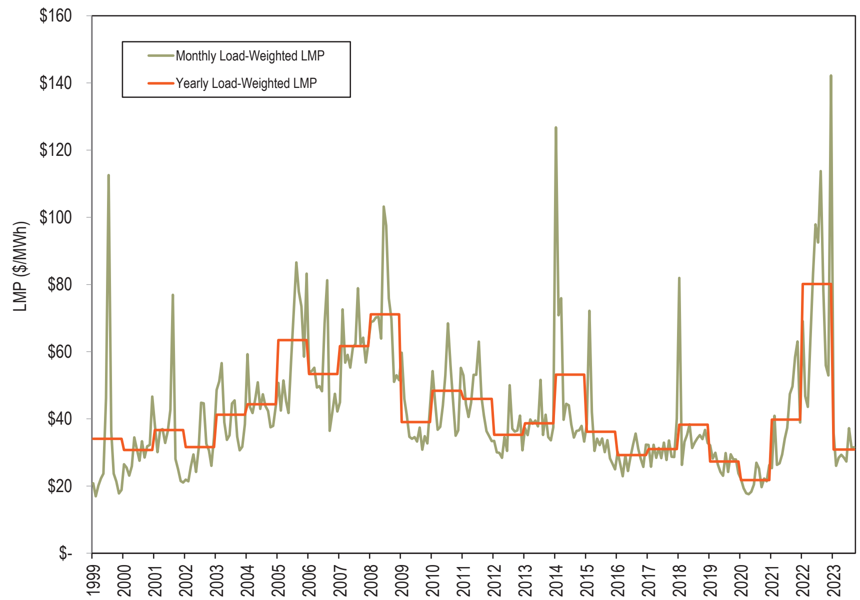


Table 3-38 shows the real-time monthly on peak and off peak load-weighted average LMP for 2022 through September 2023.

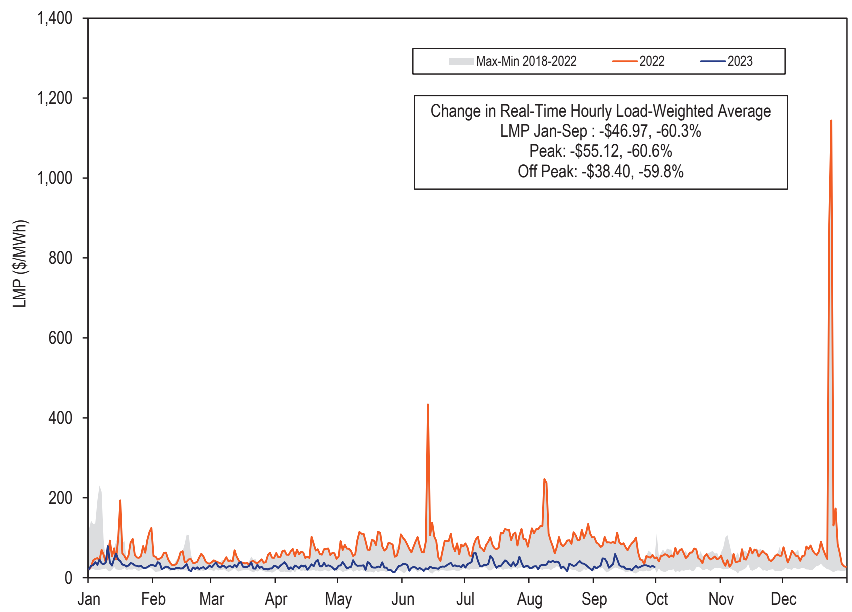
Table 3-38 Real-time monthly on peak and off peak load-weighted average LMP (Dollars per MWh): 2022 through September 2023

	2022				2023			
	Off Peak	On Peak	Difference	Percent Difference	Off Peak	On Peak	Difference	Percent Difference
Jan	$74.99	$62.54	($12.46)	(16.6%)	$33.20	$38.53	$5.32	16.0%
Feb	$45.70	$47.86	$2.16	4.7%	$23.45	$28.67	$5.22	22.3%
Mar	$41.58	$45.41	$3.83	9.2%	$26.96	$29.78	$2.82	10.5%
Apr	$55.93	$71.89	$15.96	28.5%	$24.08	$35.00	$10.92	45.4%
May	$66.12	$100.85	$34.73	52.5%	$22.65	$33.84	$11.19	49.4%
Jun	$61.63	$126.83	$65.20	105.8%	$21.64	$32.16	$10.52	48.6%
Jul	$71.83	$114.13	$42.31	58.9%	$26.86	$48.04	$21.18	78.9%
Aug	$85.89	$136.31	$50.42	58.7%	$26.68	$35.31	$8.63	32.3%
Sep	$66.36	$89.76	$23.40	35.3%	$24.76	$38.65	$13.88	56.1%
Oct	$47.61	$64.50	$16.90	35.5%				
Nov	$45.48	$60.50	$15.01	33.0%				
Dec	$153.54	$129.51	($24.03)	(15.7%)				

PJM Real-Time Daily Load-Weighted Average LMP

Figure 3-29 shows the real-time daily load-weighted average LMP for 2022 through September 2023.

Figure 3-29 Real-time daily load-weighted average LMP: 2022 through September 2023



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

Figure 3-30 shows the PJM real-time monthly load-weighted average LMP and inflation adjusted monthly load-weighted average LMP from January 1998 through September 2023.[89] Table 3-39 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 2023.

Figure 3-30 Real-time monthly load-weighted average LMP unadjusted and adjusted for inflation: January 1998 through September 2023

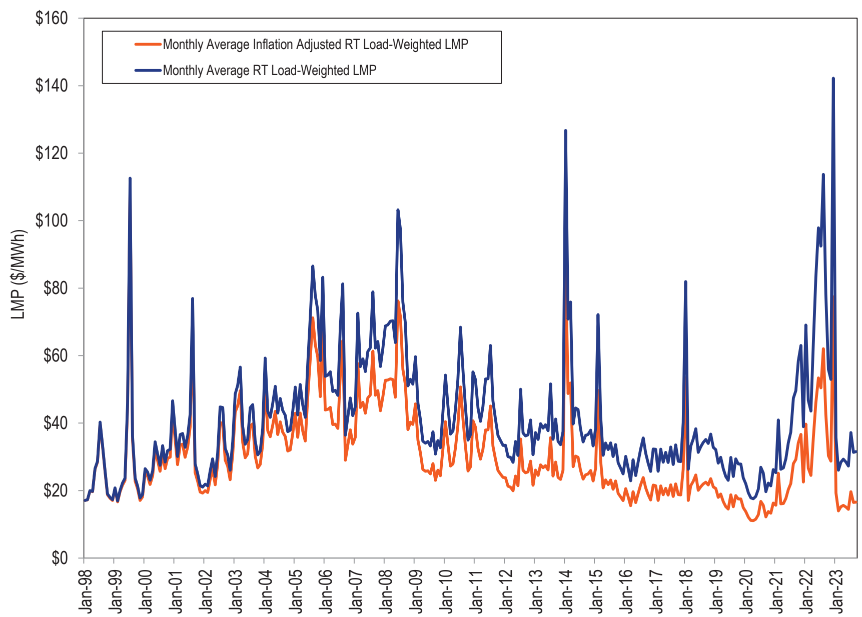


Table 3-39 Real-time load-weighted and inflation adjusted load-weighted average LMP: January through September, 1998 through 2023

	Load-Weighted Average LMP Jan-Sep	Inflation Adjusted Load-Weighted Average LMP Jan-Sep
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
2020	$21.22	$13.27
2021	$35.68	$21.39
2022	$77.84	$43.04
2023	$30.87	$16.41

Real-Time Dispatch and Pricing

On November 1, 2021, PJM implemented a new real-time dispatch process that aligned the timing of dispatch and pricing in the real-time energy market. The PJM Real-Time Energy Market is based on applications that produce the generator dispatch for energy and reserves, and five minute locational marginal prices (LMPs). These applications include the real-time security constrained economic dispatch (RT SCED), the locational pricing calculator (LPC), and the ancillary services optimizer (ASO).[90] The final real-time LMPs and ancillary service clearing prices are determined for every five minute interval by LPC.

89 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 12, 2023)

90 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 126 (May 31, 2023)

Real-Time SCED and LPC

LPC uses data from an approved RT SCED solution that was used to dispatch the resources in the system. RT SCED solves to meet load and reserve requirements forecast at a future point in time, called the target time. Prior to 2021, on average, PJM operators approved more than one RT SCED solution per five minute target time to send dispatch signals to resources. In 2021, 2022, and the first nine months of 2023, on average, PJM operators approved one RT SCED solution per five minute target time to send dispatch signals to resources. PJM uses a subset of these approved RT SCED solutions in LPC to calculate real-time LMPs every five minutes. Prior to October 15, 2020, LPC used the latest available approved RT SCED solution to calculate prices, regardless of the target dispatch time of the RT SCED solution, but LPC assigned the prices to a five minute interval that did not contain the target time of the RT SCED case it used. On October 15, 2020, PJM updated its pricing process to use an approved RT SCED solution that solves for the same target time as the end of each five minute pricing interval to calculate LMPs applicable for that five minute interval, although the SCED cases were still for 10 minutes ahead while the LPC cases were for each five minute interval. As a result, under the default timing of case approvals, resources followed the dispatch signal in the first five minutes after the RT SCED case approval and the corresponding pricing occurred five minutes after the same case approval, when resources were following a new dispatch signal. On November 1, 2021, PJM implemented changes to RT SCED that solved the energy dispatch case using a five-minute dispatch period, and ramped resources for five minutes to meet the load and reserve requirements at the end of each five minute period. The approved RT SCED solution that dispatched units for each five minute period was also used to calculate prices for the same five minute interval, aligning the prices with the concurrent dispatch signals.

Table 3-40 shows the number of RT SCED case solutions, the number of solutions that were approved, and the number and percent of approved solutions used in LPC. The RT SCED execution frequency is once every five minutes. PJM operators have the ability to execute additional RT SCED cases. Each execution of RT SCED produces five solutions, using five different levels of load bias. Since prices are calculated every five minutes while five SCED solutions are produced every five minutes, there is, by definition, a larger number of SCED solutions than there are five minute intervals in any given period.

Table 3-40 shows that in the first nine months of 2023, 97.6 percent of approved RT SCED solutions that were used to send dispatch signals to generators were used in calculating real-time energy market prices, compared to 96.5 percent in all of 2022.

Table 3-40 RT SCED cases solved, approved and used in pricing: 2022 and January through September, 2023

	2022				2023			
Month	Number of RT SCED Solutions	Number of Approved RT SCED Solutions	Number of Approved RT SCED Solutions Used in LPC	RT SCED Solutions Used in LPC as Percent of Approved RT SCED Solutions	Number of RT SCED Solutions	Number of Approved RT SCED Solutions	Number of Approved RT SCED Solutions Used in LPC	RT SCED Solutions Used in LPC as Percent of Approved RT SCED Solutions
Jan	46,494	9,035	8,846	97.9%	45,175	9,075	8,900	98.1%
Feb	41,456	8,281	8,001	96.6%	40,924	8,225	7,987	97.1%
Mar	45,704	9,296	8,863	95.3%	44,876	9,016	8,861	98.3%
Apr	44,155	8,832	8,566	97.0%	43,823	8,761	8,563	97.7%
May	45,385	9,118	8,862	97.2%	46,378	8,994	8,808	97.9%
Jun	43,995	8,900	8,605	96.7%	44,228	8,800	8,598	97.7%
Jul	45,453	9,151	8,879	97.0%	45,809	9,202	8,916	96.9%
Aug	45,161	9,395	8,869	94.4%	45,498	9,047	8,779	97.0%
Sep	43,623	8,956	8,523	95.2%	44,325	8,794	8,607	97.9%
Oct	45,384	9,041	8,779	97.1%				
Nov	44,080	9,000	8,594	95.5%				
Dec	45,334	8,967	8,822	98.4%				
Total	536,224	107,972	104,209	96.5%	401,036	79,914	78,019	97.6%

Until November 1, 2021, PJM did not link dispatch and settlement intervals. RT SCED moved from automatically executing a case every three minutes to every five minutes in 2020, while settlements are linked to five minute intervals. Until November 1, 2021, RT SCED solved the dispatch problem for a target time that was generally 14 minutes in the future. An RT SCED case was approved and sent dispatch signals to generators based on a 10 minute ramp time. The look ahead time for the load forecast and the look ahead time for the resource dispatch target did not match, and a new RT SCED case would override the previously approved case before resources had time to achieve the previous target dispatch. Prior to October 15, 2020, the interval that was priced in LPC was consistently before the target time from the RT SCED case used for the dispatch signal. LPC took the most recently approved RT SCED case to calculate LMPs for the present five minute interval. For example, the LPC case that calculated prices for the interval ending 10:05 EPT used an approved RT SCED case that sent MW dispatch signals for the target time of 10:10 EPT. This discrepancy created a mismatch between the MW dispatch and real-time LMPs and undermined generators' incentive to follow dispatch. Under new RT SCED changes that were implemented on October 15, 2020, PJM resolved the mismatch between LPC and the RT SCED target time, but prices no longer applied at the time when resources received and followed that dispatch signal.[91] For example, the LPC case that calculated prices for the interval ending 1005 EPT used an approved RT SCED case that sent MW dispatch signals at 955 EPT which were no longer effective from 10:00 to 1005 EPT. In the first 10 months of 2021, there was a mismatch between the MW dispatch and real-time LMPs that undermined generators' incentive to follow dispatch. The timing remained incorrect until all three (the pricing interval, the dispatch interval, and the RT SCED target time) all corresponded to one another, which PJM implemented on November 1, 2021.

The extent to which dispatch instructions from approved SCED solutions are reflected in concurrent prices in the PJM Real-Time Energy Market can be measured by comparing the start and end times when the dispatch instructions from the RT SCED solution were effective with the start and end times when the corresponding prices applied. The start time for a dispatch instruction is the time at which PJM approves the RT SCED solution, which triggers sending the resulting dispatch instructions to resources. The end time for a dispatch instruction is the time when the next RT SCED solution is approved. Dispatch and pricing are perfectly aligned when the start and end times of the dispatch instructions from an approved RT SCED solution match with the start and end times of the LPC pricing interval that uses the same RT SCED solution. In a perfectly aligned five minute market, these times would both be five minutes in duration. In the first 10 months of 2021, RT SCED used a 10 minute ramp time to dispatch resources, while LPC applied prices to five minute intervals. Beginning November 1, 2021, both RT SCED and LPC used the same five

91 See Docket No. ER19-2573-000.

minute period to dispatch resources and calculate prices, which aligned the dispatch signals and prices in the real-time energy market.

Table 3-41 shows the average duration of the period when dispatch instructions corresponded to the prevailing prices. Prior to October 15, 2020, PJM used the latest approved RT SCED solution available at the time of LPC execution, regardless of the SCED target time, to calculate prices for the current five minute pricing interval. The average duration of correspondence ranged from 3 minutes 11 seconds to 3 minutes 37 seconds from January through October 15, 2020, varying with changes to the frequency of automatic RT SCED execution. The percent of time that prices were consistent with the dispatch instructions was 67.2 to 69.9 percent, on average. This was far from the goal of 100 percent correspondence between five minute dispatch instructions and prices. With the short term changes to RT SCED that were implemented on October 15, 2020, the prices no longer corresponded to the dispatch instructions. Table 3-41 shows that during the first 10 months of 2021, the dispatch instructions were consistent with prevailing prices for only 33 seconds. During this period, the percent of time that prices were consistent with the dispatch instructions was 9.0 percent. In the period beginning November 1, 2021, PJM aligned the dispatch and pricing intervals such that the prices that were effective for each five minute interval were generally based on the RT SCED case that sent dispatch signals with the target time at the end of the five minute interval. As a result of these changes, in 2022, the dispatch instructions were consistent with the prices on average for 4 minutes and 45 seconds out of each five minute interval, or 95.7 percent of each five minute interval. In the first nine months of 2023, the dispatch instructions were consistent with prices on average for 4 minutes and 46 seconds out of each five minute interval, or 95.8 percent of each five minute interval.

Table 3-41 Dispatch instructions reflected in prices: January 2020 through September 2023

Period	RT SCED Automatic Execution Frequency	Dispatch Duration Reflected in Prices (Minutes:Seconds)	Percent Dispatch Duration Reflected in Prices
Jan 1, 2020 - Feb 23, 2020	Every 3 minutes	03:11	67.9%
Feb 24, 2020 - Jun 22, 2020	Every 4 minutes	03:27	67.2%
Jun 23, 2020 - Oct 14, 2020	Every 5 minutes	03:37	69.9%
Oct 15, 2020 - Dec 31, 2020	Every 5 minutes	00:39	9.9%
Jan 1, 2021 - Oct 31, 2021	Every 5 minutes	00:33	9.0%
Nov 1, 2021 - Dec 31, 2021	Every 5 minutes	04:46	95.4%
Jan 1, 2022 - Dec 31, 2022	Every 5 minutes	04:45	95.6%
Jan 1, 2023 - Jun 30, 2023	Every 5 minutes	04:47	95.8%

Recalculation of Five Minute Real-Time Prices

PJM's five minute interval LMPs are obtained from solved LPC cases. PJM recalculates five minute interval real-time LMPs as it believes necessary to correct errors. To do so, PJM reruns LPC cases with modified inputs. The PJM OATT allows for posting of recalculated real-time prices no later than 1700 (EPT) of the tenth calendar day following the operating day. The OATT also requires PJM to notify market participants of the underlying error no later than 1700 (EPT) of the second business day following the operating day.[92] Table 3-42 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 2022 and first nine months of 2023. In the first nine months of 2023, PJM recalculated LMPs for 2,205 five minute intervals or 2.80 percent of the total 78,612 five minute intervals.

92 OA Schedule 1 § 1.10.8(e).

Table 3-42 Number of five minute interval real-time prices recalculated: January 2022 through September 2023

	2022 (Jan - Sep)		2023 (Jan - Sep)	
Month	Number of Five Minute Intervals	Number of Five Minute Intervals for Which LMPs Were Recalculated	Number of Five Minute Intervals	Number of Five Minute Intervals for Which LMPs Were Recalculated
January	8,928	179	8,928	161
February	8,064	663	8,064	166
March	8,916	361	8,916	123
April	8,640	345	8,640	234
May	8,928	188	8,928	337
June	8,640	170	8,640	165
July	8,928	218	8,928	229
August	8,928	339	8,928	615
September	8,640	343	8,640	175
October	8,928	364	-	-
November	8,652	254	-	-
December	8,928	211	-	-
Total	105,120	3,635	78,612	2,205

Day-Ahead Average LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[93]

PJM Day-Ahead Average LMP

Table 3-43 shows the day-ahead average LMP for the first nine months of 2001 through 2023. The day-ahead average LMP for the first nine months of 2023 decreased $42.26 per MWh, or 58.4 percent from the first nine months of 2022, from $72.36 per MWh to $30.10 per MWh.

Table 3-43 Day-ahead average LMP (Dollars per MWh): January through September, 2001 to 2023

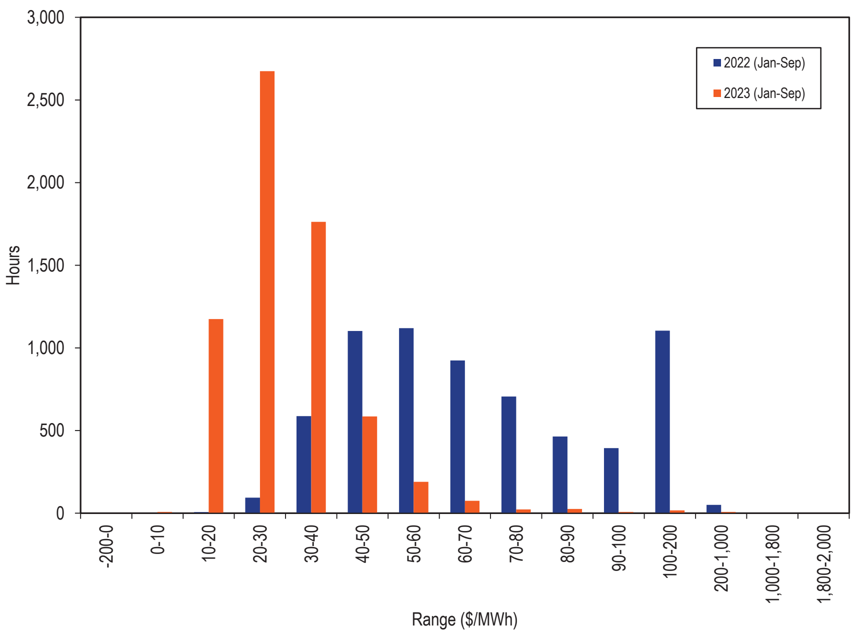
	Day-Ahead LMP			Year to Year Change			
Jan-Sep	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
2001	$36.07	$30.02	$34.25	NA	NA	NA	NA
2002	$28.29	$22.54	$19.09	($7.78)	(21.6%)	(24.9%)	(44.3%)
2003	$41.20	$38.24	$22.02	$12.91	45.6%	69.7%	15.4%
2004	$42.64	$42.07	$17.47	$1.44	3.5%	10.0%	(20.7%)
2005	$54.48	$46.67	$28.83	$11.85	27.8%	10.9%	65.1%
2006	$50.45	$46.32	$24.93	($4.03)	(7.4%)	(0.8%)	(13.5%)
2007	$54.24	$51.40	$24.95	$3.79	7.5%	11.0%	0.1%
2008	$71.43	$66.38	$33.11	$17.19	31.7%	29.2%	32.7%
2009	$37.35	$35.29	$14.32	($34.08)	(47.7%)	(46.8%)	(56.8%)
2010	$45.81	$41.03	$19.59	$8.46	22.7%	16.3%	36.8%
2011	$45.14	$40.20	$22.68	($0.67)	(1.5%)	(2.0%)	15.7%
2012	$32.16	$30.10	$14.54	($12.98)	(28.8%)	(25.1%)	(35.9%)
2013	$37.50	$34.70	$16.96	$5.34	16.6%	15.3%	16.6%
2014	$53.76	$39.92	$58.98	$16.26	43.4%	15.0%	247.8%
2015	$36.67	$30.56	$25.21	($17.09)	(31.8%)	(23.4%)	(57.3%)
2016	$27.90	$25.23	$11.37	($8.76)	(23.9%)	(17.4%)	(54.9%)
2017	$28.90	$26.60	$10.73	$0.99	3.6%	5.4%	(5.6%)
2018	$36.04	$29.75	$25.12	$7.14	24.7%	11.8%	134.2%
2019	$26.41	$24.76	$9.58	($9.63)	(26.7%)	(16.8%)	(61.9%)
2020	$19.72	$18.47	$6.99	($6.69)	(25.3%)	(25.4%)	(27.0%)
2021	$33.34	$28.28	$16.54	$13.63	69.1%	53.1%	136.7%
2022	$72.36	$63.56	$33.81	$39.02	117.0%	124.8%	104.4%
2023	$30.10	$27.83	$15.28	($42.26)	(58.4%)	(56.2%)	(54.8%)

93 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 Duration

Figure 3-31 shows the hourly distribution of the day-ahead average LMP in the first nine months of 2022 and 2023.

Figure 3-31 Distribution of day-ahead LMP: January through September, 2022 and 2023



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 3-44 shows the day-ahead load-weighted average LMP for the first nine months of 2001 through 2023. The day-ahead load-weighted average LMP in the first nine months of 2023 decreased $45.07, or 58.6 percent from the first nine months of 2022, from $76.97 per MWh to $31.90 per MWh. This is the largest dollar and percent decrease in PJM day-ahead load-weighted average LMP for the first three quarters of the year since competitive markets were introduced in 1999.

Table 3-44 Day-ahead load-weighted average LMP (Dollars per MWh): January through September, 2001 to 2023

	Day-Ahead Load-Weighted Average LMP			Year to Year Change			
Jan-Sep	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
2001	$39.88	$32.68	$42.01	NA	NA	NA	NA
2002	$32.29	$25.22	$22.81	($7.59)	(19.0%)	(22.8%)	(45.7%)
2003	$44.11	$41.51	$22.34	$11.82	36.6%	64.6%	(2.1%)
2004	$44.59	$44.47	$17.40	$0.49	1.1%	7.1%	(22.1%)
2005	$59.51	$51.33	$31.13	$14.92	33.5%	15.4%	78.9%
2006	$54.19	$48.87	$28.35	($5.32)	(8.9%)	(4.8%)	(8.9%)
2007	$57.79	$55.62	$26.07	$3.59	6.6%	13.8%	(8.0%)
2008	$75.96	$70.35	$35.19	$18.18	31.5%	26.5%	35.0%
2009	$39.35	$36.92	$14.98	($36.61)	(48.2%)	(47.5%)	(57.4%)
2010	$49.12	$43.33	$21.35	$9.77	24.8%	17.4%	42.6%
2011	$48.34	$42.35	$26.54	($0.78)	(1.6%)	(2.3%)	24.3%
2012	$34.29	$31.17	$17.12	($14.05)	(29.1%)	(26.4%)	(35.5%)
2013	$39.49	$35.96	$19.90	$5.20	15.1%	15.4%	16.3%
2014	$59.09	$42.08	$67.27	$19.60	49.6%	17.0%	238.0%
2015	$39.51	$32.15	$28.05	($19.58)	(33.1%)	(23.6%)	(58.3%)
2016	$29.69	$26.60	$12.38	($9.82)	(24.8%)	(17.3%)	(55.8%)
2017	$30.26	$27.95	$11.59	$0.56	1.9%	5.1%	(6.4%)
2018	$38.71	$31.62	$27.75	$8.45	27.9%	13.1%	139.5%
2019	$27.70	$25.85	$10.40	($11.01)	(28.4%)	(18.3%)	(62.5%)
2020	$20.95	$19.23	$7.75	($6.75)	(24.4%)	(25.6%)	(25.4%)
2021	$35.51	$30.01	$17.97	$14.57	69.5%	56.0%	131.8%
2022	$76.97	$67.42	$36.82	$41.46	116.7%	124.7%	104.9%
2023	$31.90	$29.08	$17.68	($45.07)	(58.6%)	(56.9%)	(52.0%)

PJM Day-Ahead Monthly Load-Weighted Average LMP

Figure 3-32 shows the day-ahead monthly and yearly load-weighted average LMP in 2001 through September 2023.

Figure 3-32 Day-ahead monthly and yearly load-weighted average LMP: 2001 through September 2023

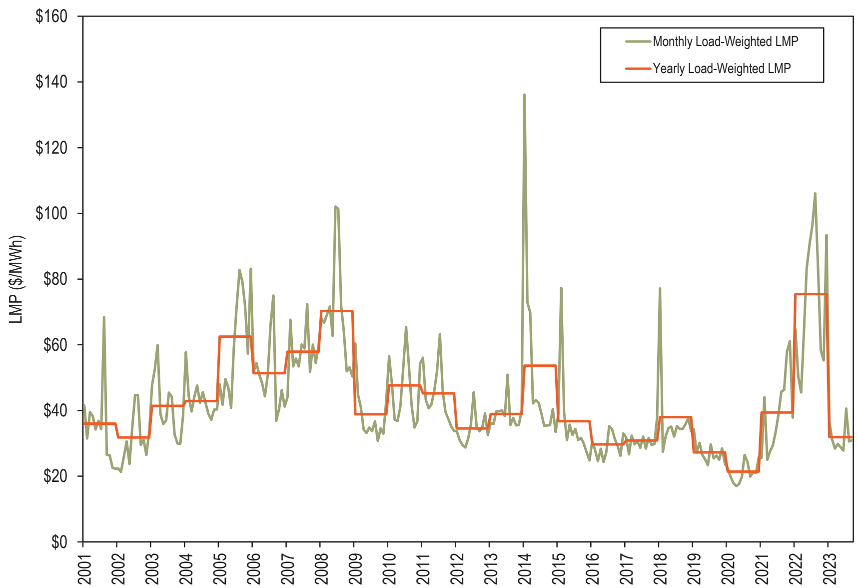
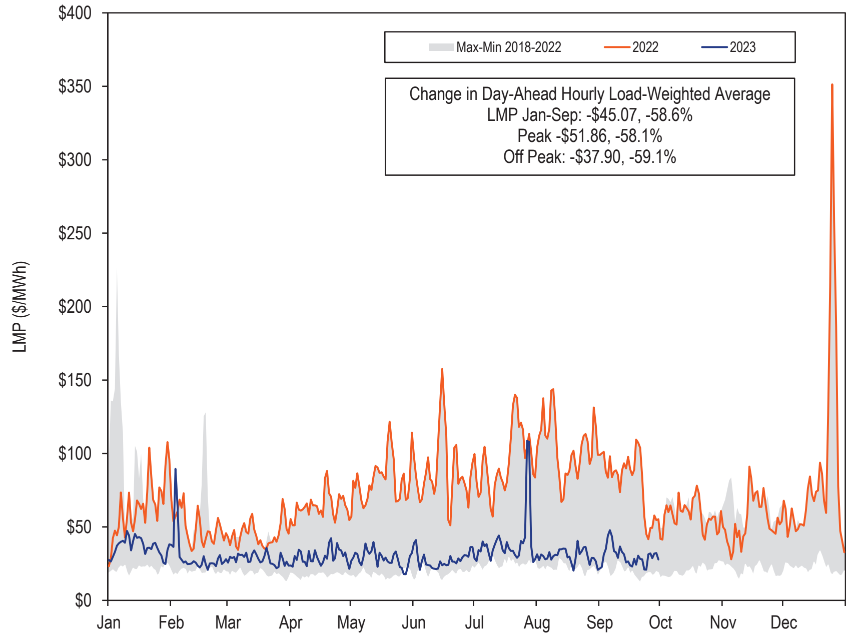


Figure 3-33 shows the day-ahead daily load-weighted average LMP in 2022 through September 2023 compared to the historic five year price range.

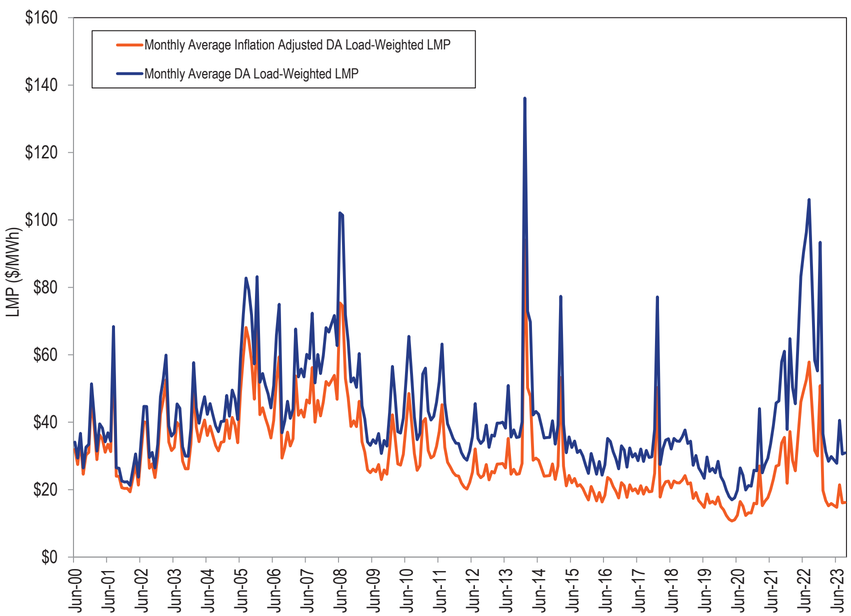
Figure 3-33 Day-ahead daily load-weighted average LMP: 2022 through September 2023



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

Figure 3-34 shows the PJM day-ahead monthly load-weighted average LMP and inflation adjusted monthly day-ahead load-weighted average LMP for September 2000 through September 2023.[94] Table 3-45 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 2023.

Figure 3-34 Day-ahead monthly load-weighted and inflation adjusted load-weighted average LMP: June 2000 through September 2023



94 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 12, 2023).

Table 3-45 Day-ahead yearly load-weighted and inflation adjusted load-weighted average LMP: January through September, 2001 through 2023

	Load-Weighted Average LMP Jan-Sep	Inflation Adjusted Load-Weighted Average LMP Jan-Sep
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
2020	$20.95	$13.09
2021	$35.51	$21.30
2022	$76.97	$42.57
2023	$31.90	$16.96

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.

In practice, virtuals can receive a positive profit whenever there is a difference in prices at any location in any hour between the day-ahead and real-time energy markets that is greater than uplift and administrative charges.

Virtual trading can only result in price convergence at a given location and market hour if the factors affecting prices at that location and hour, such as modeled contingencies, transmission constraint limits and sources of flows, are the same in both the day-ahead and real-time models.

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 result in positive profits for the virtual 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 and without improving the efficiency of the energy market. This is termed false arbitrage.

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 uplift 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.

INCs, DECs and UTCs allow participants to benefit from price differences between the day-ahead and real-time energy market. In theory, virtual transactions receive positive profits, after uplift and administrative charges, when they contribute to price convergence, but with false arbitrage, profits result with little or no price convergence. 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, after uplift and administrative charges, the INC is profitable. 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, after uplift and administrative charges, the DEC is profitable.

The profit of a UTC transaction is the net of the separate revenues of the component INC and DEC, after uplift and administrative charges. A UTC can be profitable if the profits on one side of the UTC transaction exceed the losses on the other side.

Virtual transactions, including UTCs since November 1, 2020, are required to pay uplift charges. Cleared INCs and DECs pay deviation charges based on the daily RTO and applicable regional operating reserve charge rates. DECs pay day-ahead operating reserve charges in addition to deviation charges. Cleared UTCs are treated, for uplift purposes, like DECs at the UTC sink point, and pay the regional and RTO deviation rates in addition to the day-ahead rate. Uplift charges for deviations may not apply if the virtual transaction is partially or fully offset by a corresponding real-time physical transaction at the same location.

Profitability of Virtual Transactions

The profit of a virtual transaction equals its net day-ahead and real-time energy market revenues minus uplift and administrative charges.

Table 3-46 shows, for cleared UTCs, the number of UTCs, the number of profitable UTCs, and the number of UTCs profitable at their source point, at their sink point, and at both points in the first nine months of 2022 and 2023. In the first nine months of 2023, 41.6 percent of all cleared UTC transactions were profitable. Of cleared UTC transactions, 65.9 percent were profitable on the source side and 33.5 percent were profitable on the sink side, but only 6.8 percent were profitable on both the source and sink side.

Table 3-46 Cleared UTCs with positive profits at source and sink points: January through September, 2022 and 2023[95]

(Jan-Sep)	Number of Cleared UTCs	Number of Profitable UTCs	Profitable at Source	Profitable at Sink	Profitable at Source and Sink	Share Profitable Overall	Share Profitable Source	Share Profitable Sink	Share Profitable Source and Sink
2022	3,826,397	1,761,305	2,554,271	1,311,217	320,066	46.0%	66.8%	34.3%	8.4%
2023	6,290,793	2,616,310	4,147,826	2,106,464	425,144	41.6%	65.9%	33.5%	6.8%

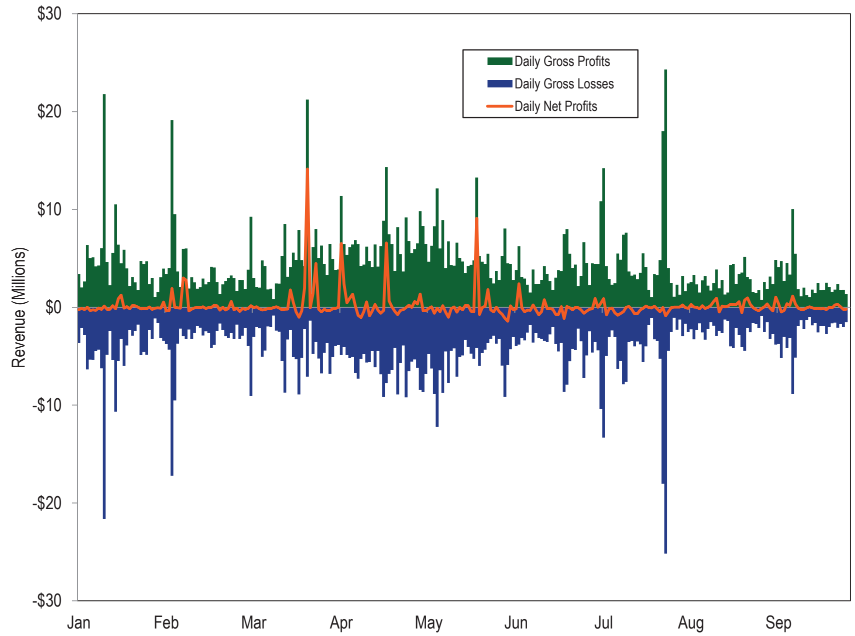
Table 3-47 shows the number of cleared INC and DEC transactions and the number of profitable transactions in the first nine months of 2022 and 2023. Of cleared INC and DEC transactions in the first nine months of 2023, 64.7 percent of INCs were profitable and 35.2 percent of DECs were profitable.

Table 3-47 Cleared INC and DEC transactions with positive profits: January through September, 2022 and 2023

(Jan-Sep)	Cleared INC	Profitable INC	Profitable INC Share	Cleared DEC	Profitable DEC	Profitable DEC Share
2022	1,960,138	1,274,140	65.0%	1,726,190	601,163	34.8%
2023	2,343,846	1,515,772	64.7%	2,254,902	793,643	35.2%

Figure 3-35 shows the positive, negative, and net daily profits for UTCs in the first nine months of 2023.

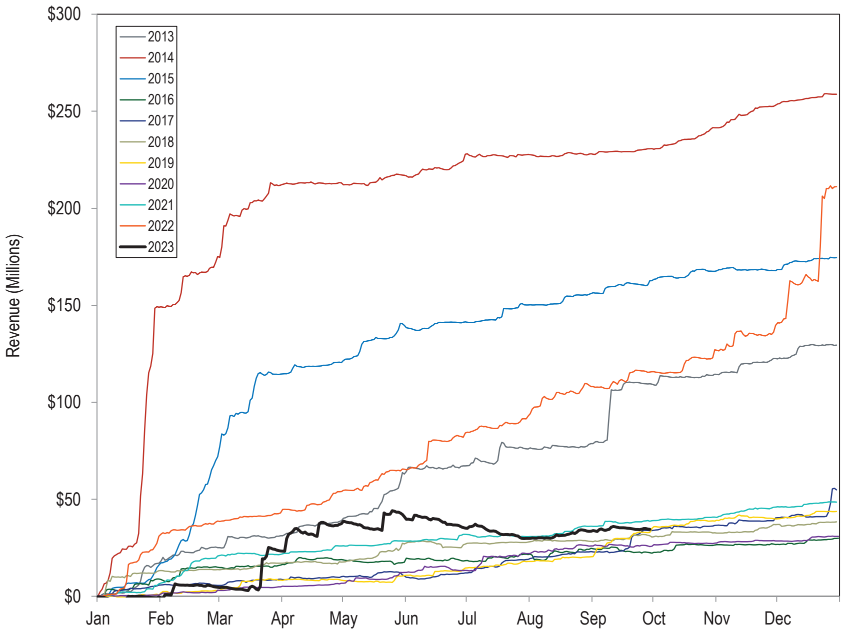
Figure 3-35 Positive, negative, and net daily UTC profits: January through September, 2023



95 Calculations exclude PJM administrative charges.

Figure 3-36 shows the cumulative UTC daily total net profits for each year from 2013 through the first nine months of 2023.[96] Administrative charges are included for all dates, and uplift charges are included starting from November 1, 2020, when these charges were first applied to UTCs. Total UTC profits were higher in 2022 than any year since 2014. In the first nine months of 2023, the most profitable UTC transactions were concentrated in the Dominion Zone and on dates with high real-time congestion in the Dominion Zone, which occurred primarily in January through May 2023.

Figure 3-36 Cumulative daily UTC profits: January 2013 through September 2023



96 UTCs paid uplift only after October 31, 2020.

Table 3-48 shows UTC profits by month for January 2013 through September 2023. The totals include administrative charges for all months and uplift charges beginning in November 2020, when UTCs first became subject to uplift charges. UTC profits were $211 million in 2022, higher than any year since 2014, with the largest monthly totals in December at $75 million and January at $31 million. June and July 2023 were the least profitable months in Table 3-48, as a result of continued bidding on the DOMINION HUB to DOM_RESID_AGG UTC path in the day-ahead market despite a change in real-time market results.

Table 3-48 UTC profits by month: January 2013 through September 2023

	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	$5,914,042	$1,171,145	$3,722,403	$43,734,418
2020	$664,972	$2,497,856	$1,720,037	$1,865,139	$5,508,276	$1,123,429	$8,573,276	$3,957,296	($141,240)	$1,628,186	$1,170,367	$2,319,727	$30,887,320
2021	$6,421,567	$13,241,294	$1,788,961	$4,529,921	$2,542,898	$3,384,291	($1,199,849)	$5,330,600	$2,649,331	$2,148,861	$5,091,590	$2,665,873	$48,595,339
2022	$30,954,077	$7,236,325	$4,411,627	$11,317,095	$11,658,586	$16,398,181	$9,481,970	$17,376,381	$6,783,480	$7,325,933	$13,116,641	$75,067,601	$211,127,897
2023	($374,877)	$5,180,921	$18,722,180	$13,543,116	$5,121,917	($6,820,656)	($5,587,077)	$3,667,565	$1,041,650				$34,494,740

Figure 3-37 shows the positive, negative, and net daily profits for INCs and DECs in the first nine months of 2023. Differences in the modeling of transmission constraints and other system constraints such as reserves between day ahead and real time, including the use of different constraint limits or a constraint being modeled in one market but not the other, remain a principal source of false arbitrage profits and a major reason for the overall profitability of virtual transactions.

Figure 3-37 Daily gross profits, gross losses, and net profits of all INC and DEC transactions: January through September, 2023[97]

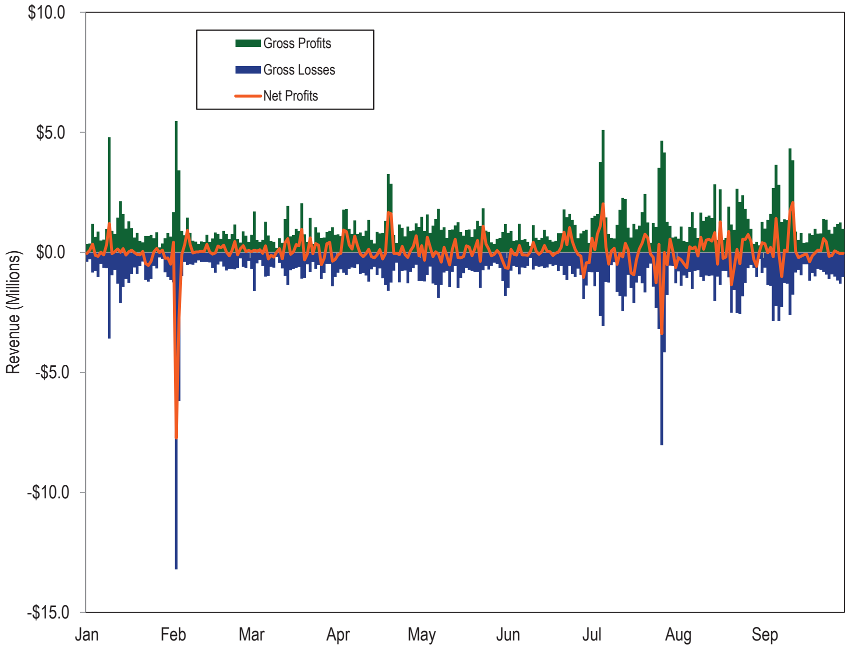
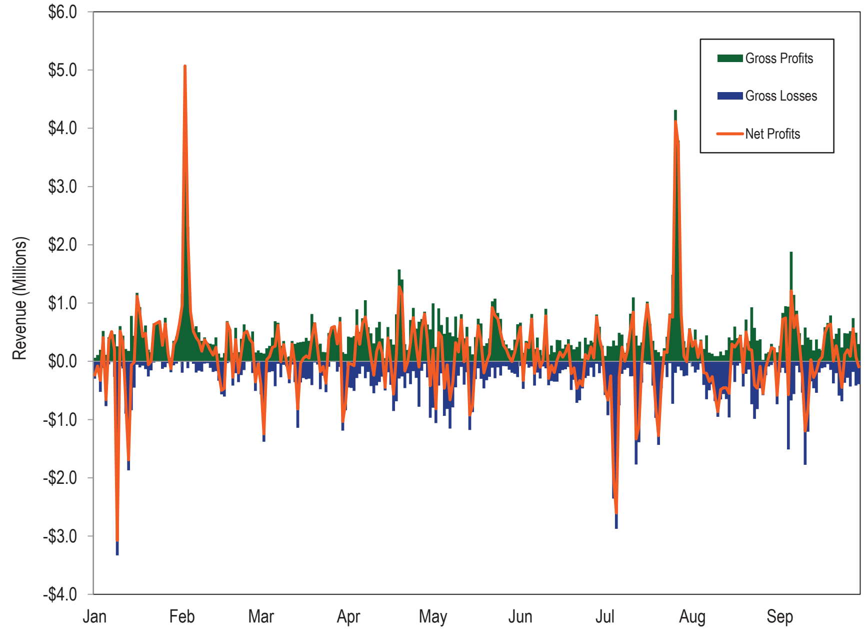


Figure 3-38 shows the positive, negative, and net daily profits for INCs in the first nine months of 2023.

Figure 3-38 Daily gross profits, gross losses, and net profits for INC transactions: January through September, 2023[98]



97 Calculations exclude PJM administrative charges.

98 Calculations exclude PJM administrative charges.

Figure 3-39 shows the positive, negative, and net daily profits for DECs in the first nine months of 2023.

Figure 3-39 Daily gross profits, gross losses, and net profits for DEC transactions: January through September, 2023

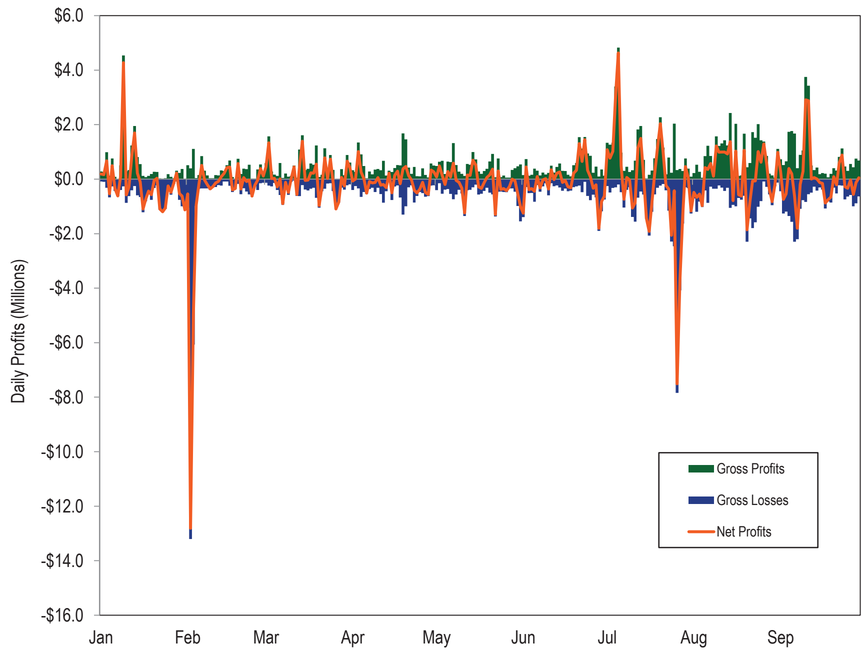


Figure 3-40 shows the cumulative INC and DEC daily profits in the first nine months of 2023. Virtual trading can be profitable without contributing to price convergence because the addition of virtual supply or demand in the day-ahead market does not and cannot correct for factors not included in the day-ahead model, such as the use of different transmission constraint limits in day ahead versus real time.

Figure 3-40 Cumulative daily INC and DEC profit: January through September, 2023

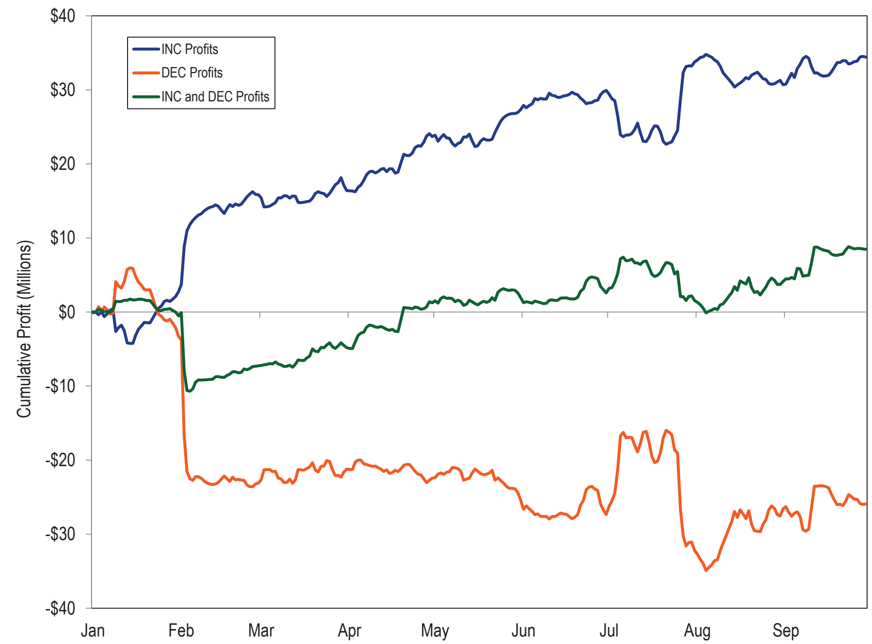


Table 3-49 shows INC and DEC profits by month in the first nine months of 2023.

Table 3-49 INC and DEC profits by month: January through September, 2023

Month	January	February	March	April	May	June	July	August	September	Total
INCs	$2,113,400	$13,773,054	$1,219,245	$6,994,194	$2,855,807	$2,782,861	$3,495,291	($1,957,147)	$3,140,489	$34,417,194
DECs	($2,128,701)	($21,084,957)	$1,590,308	($1,087,222)	($1,669,477)	($2,338,940)	($4,350,020)	$3,515,925	$1,620,947	($25,932,136)
INCs and DECs	($15,301)	($7,311,902)	$2,809,553	$5,906,972	$1,186,331	$443,921	($854,729)	$1,558,777	$4,761,436	$8,485,057

All virtual transactions are subject to uplift charges. Each cleared MWh of a virtual transaction pays uplift at the daily operating reserve charge rates, but UTCs pay uplift only at the transaction sink. Cleared increment offers pay the regional and RTO deviation rates, and cleared decrement bids pay the day-ahead rate in addition. Cleared up to congestion transactions pay the same rate as a decrement bid but only at the transaction's sink point, the day-ahead rate and RTO and regional deviation rates.

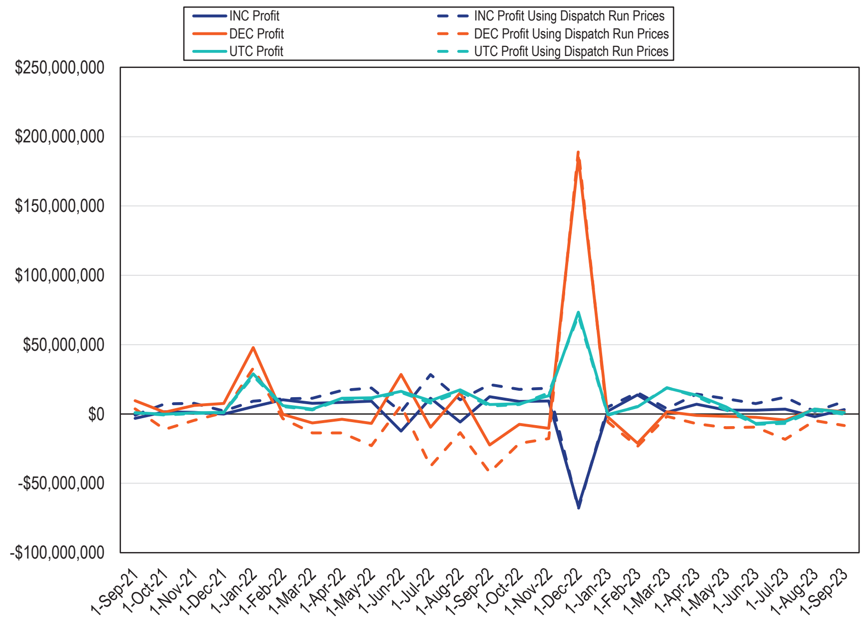
In the first nine months of 2023, INCs paid a total of $4.7 million, DECs paid a total of $7.9 million, and UTCs paid a total of $29.3 million in uplift. This compares to total INC profits of $34.4 million, total DEC losses of $25.9 million, and total UTC profits of $34.6 million.

Effect of Fast Start Pricing on Virtuals

The implementation of fast start pricing on September 1, 2021, has resulted in changes to the settlement of virtual transactions. Prior to fast start pricing, virtual products were cleared and settled based on a single set of prices. The dispatch and pricing run prices were the same. With fast start pricing, all virtual products are cleared using day-ahead dispatch run prices, but pay and receive the day-ahead and real-time pricing run prices. The use of fast start pricing has a direct effect on virtual settlements through the use of prices different from those used to dispatch virtuals. This means that a DEC may clear in the day-ahead market, based on the dispatch run, even though its offer is lower than the final, pricing run price. This means that an INC may clear even though its offer is higher than the day-ahead market price. The use of fast start pricing also results in divergence between day-ahead and real-time prices, which can be targeted by virtual traders. The fact that fast start pricing increases prices more in the real-time market, all else held equal, increases the profitability of DECs and decreases the profitability of INCs.

Figure 3-41 shows the total monthly profits received by INCs, DECs, and UTCs, compared to the profits they would have received if dispatch run prices had been used in settlement for each month since the initial implementation of fast start pricing in September 2021. Since its implementation, fast start pricing has consistently increased profits for DECs and decreased profits for INCs but has not significantly affected profits for UTCs. Fast start pricing creates a difference between day-ahead and real-time prices. Virtual traders can benefit from this difference without contributing to price convergence.

Figure 3-41 Monthly profits for virtuals using pricing run versus dispatch run prices: September 1, 2021 through September 30, 2023



From the implementation of fast start pricing on September 1, 2021, through September 30, 2023, the cumulative difference in profit between the pricing run and the dispatch run for INCs was -$160.8 million, the cumulative difference in profit for DECs was $264.4 million, and the cumulative difference in profit for UTCs was $18.7 million, a net total of $122.3 million.

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 reason to believe 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, about modeling differences 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. PJM markets do not provide a mechanism that could ever result in convergence in the presence of modeling differences.

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.

Day-ahead and Real-time Prices

Table 3-50 shows the difference between the day-ahead and the real-time average LMP for the first nine months of 2022 and 2023.

Table 3-50 Day-ahead and real-time average LMP (Dollars per MWh): January through September, 2022 and 2023[99]

	2022 (Jan-Sep)				2023 (Jan-Sep)			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$72.36	$72.57	$0.21	0.3%	$30.10	$29.29	($0.81)	(2.8%)
Median	$63.56	$59.66	($3.90)	(6.5%)	$27.83	$25.57	($2.26)	(8.8%)
Standard deviation	$33.81	$59.73	$25.92	43.4%	$15.28	$18.21	$2.93	16.1%
Peak average	$84.96	$85.78	$0.81	0.9%	$35.82	$34.58	($1.24)	(3.6%)
Peak median	$77.24	$74.66	($2.58)	(3.5%)	$32.31	$30.11	($2.19)	(7.3%)
Peak standard deviation	$38.28	$76.85	$38.57	50.2%	$18.23	$21.48	$3.24	15.1%
Off peak average	$61.23	$60.91	($0.32)	(0.5%)	$25.10	$24.66	($0.43)	(1.8%)
Off peak median	$55.97	$52.89	($3.08)	(5.8%)	$23.12	$21.42	($1.70)	(7.9%)
Off peak standard deviation	$24.38	$34.83	$10.44	30.0%	$9.66	$13.13	$3.48	26.5%

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

Table 3-51 shows the difference between the day-ahead and the real-time load-weighted LMP for the first nine months of 2001 through 2023.

Table 3-51 Day-ahead and real-time load-weighted average LMP (Dollars per MWh): January through September, 2001 through 2023

	Load-Weighted Average LMP			
Jan-Sep	Day-Ahead	Real-Time	Difference	Percent of Real-Time
2001	$39.88	$40.96	$1.09	2.7%
2002	$32.29	$31.95	($0.33)	(1.0%)
2003	$44.11	$43.57	($0.54)	(1.2%)
2004	$44.59	$46.44	$1.84	4.0%
2005	$59.51	$60.44	$0.93	1.5%
2006	$54.19	$56.39	$2.19	3.9%
2007	$57.79	$61.83	$4.05	6.5%
2008	$75.96	$77.27	$1.30	1.7%
2009	$39.35	$39.57	$0.21	0.5%
2010	$49.12	$49.91	$0.79	1.6%
2011	$48.34	$49.48	$1.14	2.3%
2012	$34.29	$35.02	$0.73	2.1%
2013	$39.49	$39.75	$0.26	0.7%
2014	$59.09	$58.60	($0.49)	(0.8%)
2015	$39.51	$38.94	($0.57)	(1.5%)
2016	$29.69	$29.32	($0.37)	(1.3%)
2017	$30.26	$30.36	$0.10	0.3%
2018	$38.71	$39.43	$0.73	1.8%
2019	$27.70	$27.60	($0.10)	(0.4%)
2020	$20.95	$21.22	$0.28	1.3%
2021	$35.51	$35.68	$0.17	0.5%
2022	$76.97	$77.84	$0.87	1.1%
2023	$31.90	$30.87	($1.03)	(3.3%)

Table 3-52 includes frequency distributions of the differences between the day-ahead and the real-time load-weighted LMP in the first nine months of 2022 and 2023.

Table 3-52 Frequency distribution by hours of real-time load-weighted LMP minus day-ahead load-weighted LMP (Dollars per MWh): January through September, 2022 and 2023

	2022 Jan - Sep		2023 Jan - Sep	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($200)	0	0.0%	3	0.0%
($200) to ($100)	3	0.0%	10	0.2%
($100) to ($50)	47	0.8%	18	0.5%
($50) to $0	4,278	66.1%	4,296	66.1%
$0 to $50	2,067	97.6%	2,174	99.2%
$50 to $100	95	99.1%	44	99.9%
$100 to $200	35	99.6%	4	100.0%
$200 to $400	17	99.9%	1	100.0%
$400 to $800	6	100.0%	1	100.0%
>= $800	3	100.0%	0	100.0%

Figure 3-42 shows the differences between day-ahead and real-time hourly average LMP in the first nine months of 2023.

The largest difference was $567.94 per MWh on January 10, 2023.

Figure 3-42 Real-time hourly average LMP minus day-ahead hourly average LMP: January through September, 2023

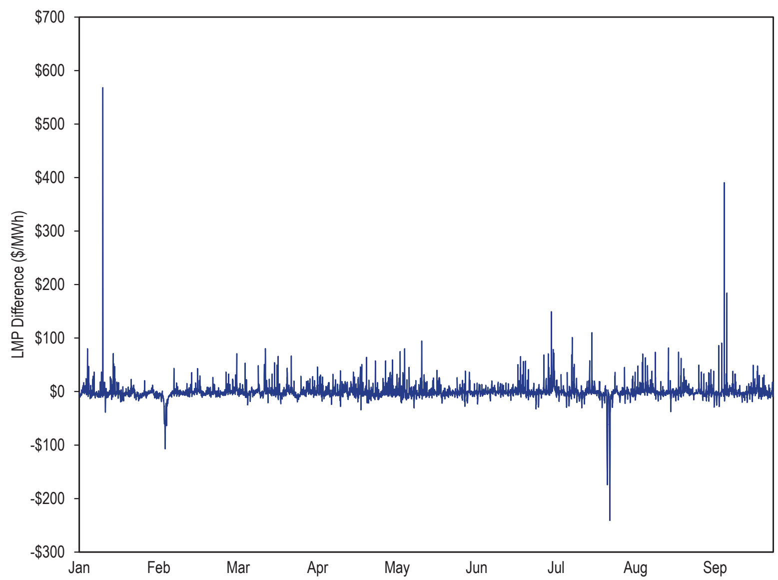
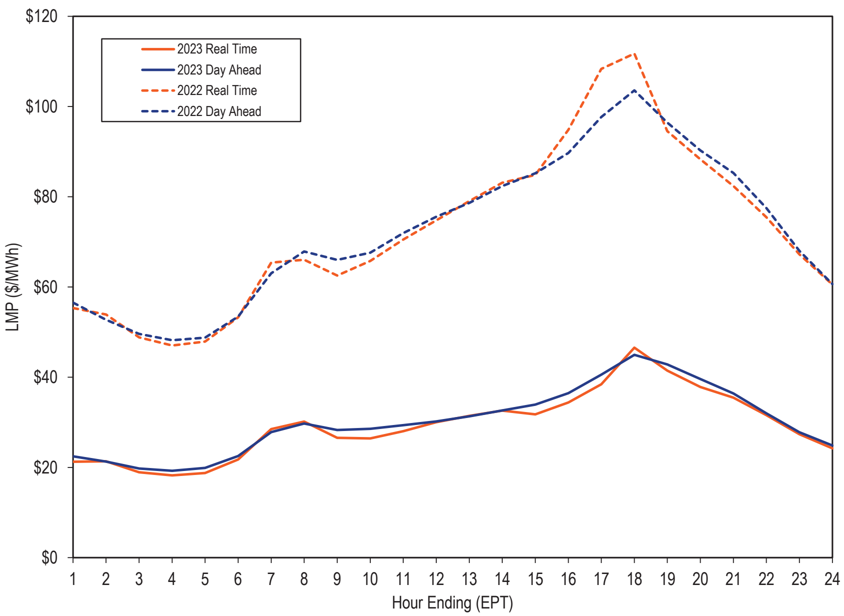


Figure 3-43 shows day-ahead and real-time load-weighted average LMP by hour of the day for the first nine months of 2022 and 2023.

Figure 3-43 System hourly average LMP: January through September, 2022 and 2023



Zonal LMP and Dispatch

Table 3-53 shows real-time zonal average and load-weighted average LMP for the first nine months of 2022 and 2023.

Table 3-53 Real-time zonal average and load-weighted average LMP (Dollars per MWh): January through September, 2022 and 2023

	Real-Time Average LMP			Real-Time Load-Weighted Average LMP		
Zone	2022 Jan-Sep	2023 Jan-Sep	Percent Change	2022 Jan-Sep	2023 Jan-Sep	Percent Change
ACEC	$65.07	$23.27	(64.2%)	$73.69	$25.20	(65.8%)
AEP	$70.53	$29.82	(57.7%)	$74.02	$31.07	(58.0%)
APS	$71.48	$30.22	(57.7%)	$75.07	$31.78	(57.7%)
ATSI	$69.16	$29.60	(57.2%)	$73.19	$30.90	(57.8%)
BGE	$84.18	$35.44	(57.9%)	$92.71	$38.13	(58.9%)
COMED	$61.13	$25.96	(57.5%)	$66.38	$27.86	(58.0%)
DAY	$72.82	$31.28	(57.0%)	$77.57	$32.82	(57.7%)
DUKE	$71.16	$30.75	(56.8%)	$76.28	$32.33	(57.6%)
DOM	$88.35	$34.82	(60.6%)	$96.46	$36.79	(61.9%)
DPL	$70.55	$27.29	(61.3%)	$80.70	$31.96	(60.4%)
DUQ	$67.90	$29.26	(56.9%)	$72.70	$30.62	(57.9%)
EKPC	$71.02	$30.31	(57.3%)	$74.84	$32.04	(57.2%)
JCPLC	$66.45	$23.90	(64.0%)	$75.30	$25.96	(65.5%)
MEC	$74.57	$25.70	(65.5%)	$81.14	$27.22	(66.4%)
OVEC	$68.93	$29.57	(57.1%)	$67.60	$29.76	(56.0%)
PECO	$64.11	$22.48	(64.9%)	$70.72	$24.02	(66.0%)
PE	$68.71	$28.57	(58.4%)	$71.43	$29.82	(58.3%)
PEPCO	$80.91	$33.73	(58.3%)	$88.97	$36.19	(59.3%)
PPL	$68.72	$23.81	(65.4%)	$73.25	$25.08	(65.8%)
PSEG	$67.84	$24.14	(64.4%)	$74.60	$25.73	(65.5%)
REC	$69.92	$25.94	(62.9%)	$78.57	$28.17	(64.1%)
PJM	$72.57	$29.29	(59.6%)	$77.84	$30.87	(60.3%)

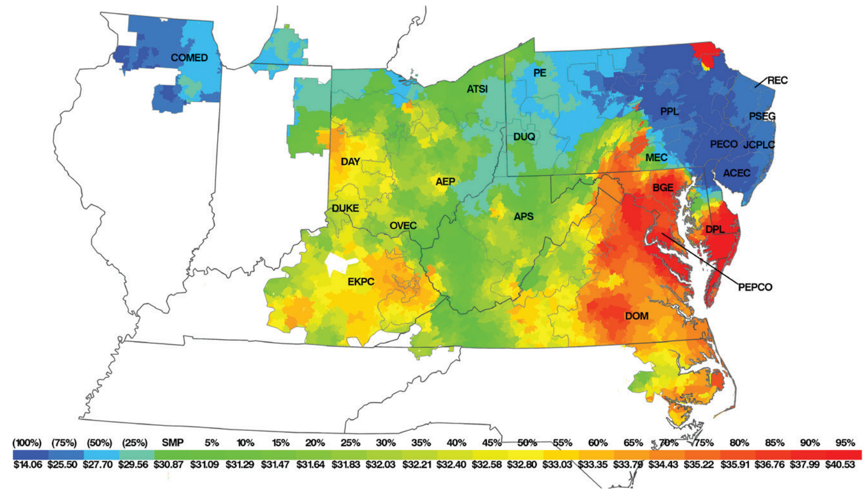
Table 3-54 shows day-ahead zonal average and load-weighted average LMP for the first nine months of 2022 and 2023.

Table 3-54 Day-ahead zonal average and load-weighted average LMP (Dollars per MWh): January through September, 2022 and 2023

	Day-Ahead Average LMP			Day-Ahead Load-Weighted Average LMP		
Zone	2022 Jan-Sep	2023 Jan-Sep	Percent Change	2022 Jan-Sep	2023 Jan-Sep	Percent Change
ACEC	$64.30	$24.07	(62.6%)	$70.80	$26.01	(63.3%)
AEP	$71.56	$30.89	(56.8%)	$75.19	$32.32	(57.0%)
APS	$72.55	$31.52	(56.6%)	$75.06	$33.23	(55.7%)
ATSI	$70.78	$30.60	(56.8%)	$74.49	$32.00	(57.0%)
BGE	$83.55	$37.58	(55.0%)	$90.51	$40.77	(55.0%)
COMED	$63.12	$26.80	(57.5%)	$68.04	$28.78	(57.7%)
DAY	$74.04	$32.39	(56.2%)	$78.54	$34.20	(56.5%)
DUKE	$72.77	$31.87	(56.2%)	$78.14	$33.74	(56.8%)
DOM	$84.73	$35.12	(58.5%)	$91.94	$37.41	(59.3%)
DPL	$68.28	$27.21	(60.1%)	$76.52	$31.97	(58.2%)
DUQ	$69.44	$30.20	(56.5%)	$73.73	$31.75	(56.9%)
EKPC	$71.87	$30.99	(56.9%)	$75.80	$33.11	(56.3%)
JCPLC	$65.54	$24.64	(62.4%)	$71.93	$26.58	(63.0%)
MEC	$75.25	$26.62	(64.6%)	$80.60	$28.50	(64.6%)
OVEC	$70.09	$30.37	(56.7%)	$72.69	$30.27	(58.4%)
PECO	$63.40	$23.19	(63.4%)	$68.60	$24.80	(63.8%)
PE	$70.26	$29.39	(58.2%)	$73.49	$31.38	(57.3%)
PEPCO	$80.57	$35.81	(55.6%)	$87.66	$38.88	(55.6%)
PPL	$69.23	$24.64	(64.4%)	$73.01	$26.10	(64.3%)
PSEG	$66.58	$24.89	(62.6%)	$71.47	$26.57	(62.8%)
REC	$69.01	$26.63	(61.4%)	$75.98	$29.30	(61.4%)
PJM	$72.36	$30.10	(58.4%)	$76.97	$31.90	(58.6%)

Figure 3-44 is a map of the real-time load-weighted average LMP for the first nine months of 2023. 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 3-44 Real-time load-weighted average LMP: January through September, 2023



Transmission Constraint Penalty Factors

LMP may, at times, be set by transmission constraint 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.

PJM operators routinely reduce the line limit on transmission constraints in the market software by setting the limit to 95 percent of its actual limit. The result is that transmission constraint penalty factors set price more frequently than needed.

Since the implementation of fast start pricing on September 1, 2021, PJM set the default level of the transmission constraint penalty factor in the pricing run of the day-ahead market at $2,000 per MWh. The default level of the transmission constraint penalty factor in the dispatch run of the day-ahead market was left unchanged at $30,000 per MWh.

Table 3-55 shows the frequency and average shadow price of transmission constraints in the PJM real-time market. In the first nine months of 2023, there were 114,963 transmission constraint intervals in the real-time market with a nonzero shadow price. For about six percent of these transmission constraint intervals, the line limit was violated, meaning that the flow exceeded the facility limit used in SCED.[100] For 69 percent of those violations, PJM had reduced the line rating. In those cases, the actual line limit was not violated. In the first nine months of 2023, the average shadow price of transmission constraints when the line limit used in SCED was violated was 8.1 times higher than when the transmission constraint was binding at its limit used in SCED.

Market to Market Transmission Constraints are categorized separately because of the unique rules governing the congestion management of these constraints by PJM and MISO. In the real-time market, PJM and MISO initiate a joint congestion management process commonly referred as “market to market” if they recognize substantial flows originating from the other RTO on their constraints. The identified constraints are then modeled in the dispatch optimizations of the both RTOs. After every approved solution, the shadow prices are exchanged between the RTOs.

Table 3-55 Frequency and average shadow price of transmission constraints in the real-time market: January through September, 2022 and 2023

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2022 (Jan - Sep)	2023 (Jan - Sep)	2022 (Jan - Sep)	2023 (Jan - Sep)
Violated Transmission Constraints	17,472	6,616	$1,807.84	$1,500.84
Binding Transmission Constraints	74,715	72,651	$254.44	$184.34
Market to Market Transmission Constraints	57,744	35,696	$471.54	$289.15
All Transmission Constraints	149,931	114,963	$519.08	$292.64

100 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.

Table 3-56 shows the frequency and average shadow price of transmission constraints in the PJM day-ahead market. In the first nine months of 2023, there were 56,285 transmission constraint hours in the day-ahead market with a nonzero shadow price. For less than one percent of these transmission constraint hours, the line limit was violated, meaning that the flow exceeded the facility limit used in the DA pricing run solution.

Table 3-56 Frequency and average shadow price of transmission constraints in the day-ahead market: January through September, 2022 and 2023

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2022 (Jan - Sep)	2023 (Jan - Sep)	2022 (Jan - Sep)	2023 (Jan - Sep)
Violated Transmission Constraints	33	10	$2,000.00	$2,000.00
Binding Transmission Constraints	41,138	50,655	$94.64	$40.26
Market to Market Transmission Constraints	8,950	5,620	$206.33	$118.61
All Transmission Constraints	50,121	56,285	$115.84	$48.43

Table 3-57 shows the frequency of violated transmission constraints by voltage level. In the first nine months of 2023, 90.9 percent of the violated transmission constraint intervals had a voltage level at or below 230 kV.

Table 3-57 Frequency of PJM violated transmission constraints by voltage: January through September, 2022 and 2023

	2022 (Jan - Sep)		2023 (Jan - Sep)	
Voltage	Frequency (Constraint Intervals)	Percent	Frequency (Constraint Intervals)	Percent
1 kV	58	0.3%	4	0.1%
69 kV	326	1.9%	102	1.5%
115 kV	4,379	25.1%	1,699	25.7%
138 kV	2,362	13.5%	1,360	20.6%
230 kV	8,793	50.3%	2,852	43.1%
345 kV	397	2.3%	452	6.8%
500 kV	1,043	6.0%	144	2.2%
765 kV	114	0.7%	3	0.0%
Total	17,472	100.0%	6,616	100.0%

Transmission penalty factors should be applied without discretion, but not without additional rules that prevent unintended consequences. PJM adopted the MMU’s recommendation to remove the constraint relaxation logic and allow transmission penalty factors to set prices in the day-ahead and real-time markets for all internal transmission constraints. But the potential for prolonged and excessively high administrative pricing in the energy market due to transmission constraint penalty factors remains an issue that needs to be addressed. There can be situations in which the application of transmission penalty factors in real time for significant periods creates manipulation opportunities for virtuals and creates inefficient wealth transfers when market participants do not have the ability to react to the high prices either on the supply or demand side.[101] This could be the result of a lengthy planned transmission outage, for example.[102] It can also result from PJM reducing the line limit in RT SCED below 100 percent of the actual line limit and triggering the transmission constraint penalty factor, while operating the system below the actual line limit for a prolonged period. PJM should not reduce transmission line limits in SCED to trigger the inclusion of transmission constraint penalty factors in price.

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. The Commission approved the PJM and MISO joint filing to remove the constraint relaxation logic for market to market constraints on March 6, 2020. PJM and MISO implemented the changes to their dispatch software in the second half of 2020. On March 21, 2023, FERC approved new rules proposed by PJM to allow for changes to the transmission penalty factors for constraints that are violated due to a transmission outage for which limited generation resources are available to provide relief.[103]

PJM routinely, based on discretion, reduces the line limit modeled in SCED to below 100 percent, generally to 95 percent of the actual limit, in order to trigger the use of transmission constraint penalty factors.[104] Table 3-58 shows the frequency of changes to the transmission constraints for binding and violated transmission constraints in the PJM real-time market. In the first nine months of 2023, there were 4,573 or 69 percent of 6,616 violated transmission constraint intervals in the real-time market with a constraint limit less than 100 percent of the actual constraint limit. In the first nine months of 2023, among the constraints with reduced constraint limits, the constraint limit was reduced on average by 5.6 percent.

Table 3-58 Frequency of reduction in line ratings (constraint intervals): January through September, 2022 and 2023

	Frequency (Constraint Intervals)		Constraints with Reduced Line Limits (Constraint Intervals)		Average Reduction (Percentage)	
Description	2022 (Jan - Sep)	2023 (Jan - Sep)	2022 (Jan - Sep)	2023 (Jan - Sep)	2022 (Jan - Sep)	2023 (Jan - Sep)
Violated Transmission Constraints	17,472	6,616	15,027	4,573	5.5%	5.6%
Binding Transmission Constraints	74,715	72,651	71,525	71,185	6.4%	6.4%
Market to Market Transmission Constraints	57,744	35,696	14,127	6,444	5.8%	5.5%
All Transmission Constraints	149,931	114,963	100,679	82,202	6.2%	6.3%

Table 3-59 shows the reasons provided by the PJM dispatchers for changing the line rating for violated transmission constraints. In the first nine months of 2023, of the 4,573 violated transmission constraints with reduced line ratings, 827 or 18.1 percent were reduced because the relief calculated by the SCED optimization was less than the dispatcher's desired relief for the transmission constraint. No reason was provided for 2,841 instances, or 62 percent of all the instances. The MMU recommends that PJM end the practice of discretionary reductions in transmission line ratings modeled in SCED. This practice has significant market effects by increasing prices above the level that would exist if the actual line rating were enforced.

101 See Comments of the Independent Market Monitor for PJM, Docket No. EL22-26-000 et al. (February 1, 2022); 178 FERC ¶ 61,104 (2022).
102 See *id.*
103 See 182 FERC ¶ 61,183 (March 21, 2023).
104 PJM does not have the authority to change the line ratings of transmission facilities. The ratings are provided by the transmission owner. The line ratings for transmission constraints used in the SCED model are reduced by PJM in these cases.

Table 3-59 PJM's reasons for reduction in line ratings (constraint intervals): January through September, 2022 and 2023

	Constraint Intervals		Average Reduction (Percentage)	
Reason	2022 (Jan - Sep)	2023 (Jan - Sep)	2022 (Jan - Sep)	2023 (Jan - Sep)
No reason provided	10,395	2,841	4.4%	4.6%
Prepositioning of generation resources to support an operational requirement	204	84	9.8%	9.6%
Inadequate relief calculated by the SCED optimization	2,401	827	7.7%	7.1%
Transmission owner identified the flow on their constraint to be greater than PJM's calculated flow on the same constraint.	507	190	8.0%	8.2%
Modeled constraint is a thermal surrogate	35	1	45.0%	94.0%
Power flow on the constraint is volatile due to various system conditions	1,485	630	7.4%	6.7%
Total	15,027	4,573	5.5%	5.6%

Table 3-60 shows the impact on LMP of PJM dispatchers reducing the line ratings of transmission constraints and causing artificial line limit violations.[105] The transmission penalty factor contribution to the load weighted average LMP in the first nine months of 2023 was $1.42 per MWh. If 100 percent of the line limits had been used for the PJM transmission constraints and everything else remained unchanged, fewer constraints would have been violated and the transmission penalty factor's contribution to the load weighted average LMP would have decreased to $0.01 per MWh or 99.2 percent lower.

Table 3-60 Real-time LMP effect of reduced line limits for PJM transmission constraints (Dollars per MWh): January through September, 2022 and 2023

	Contribution to LMP	
Line Limit Scenario for Violated Constraints	2022 (Jan - Sep)	2023 (Jan - Sep)
Line Limits Reduced by PJM (Actual)	$4.46	$1.42
Hypothetical Use of Full Line Limits	($0.11)	$0.01
Change in Contribution to LMP	($4.57)	($1.41)
Percent Change in Contribution to LMP	(102.4%)	(99.2%)

105 The MMU calculates the impact on system prices based on analysis using sensitivity factors. The transmission penalty factor contribution with actual line limits is not based on a counterfactual redispatch of the system. See Technical Reference for PJM Markets, "Calculation and Use of Generator Sensitivity/Unit Participation Factors," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 3-61 shows the frequency of changes to the magnitude of transmission penalty factors for binding and violated transmission constraints in the PJM Real-Time Energy Market. In the first nine months of 2023, there were 4,838 or 73 percent of violated transmission constraint intervals in the real-time market with a transmission penalty factor equal to the default $2,000 per MWh.

Table 3-61 Frequency of changes to the magnitude of transmission penalty factor (constraint intervals): January through September, 2022 and 2023

	2022 (Jan - Sep)			2023 (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
Violated Transmission Constraints	15,223	67	2,182	4,838	-	1,778
Binding Transmission Constraints	74,003	32	680	71,587	-	1,064
Market to Market Transmission Constraints	7,356	31	50,357	2,158	-	33,538
All Transmission Constraints	96,582	130	53,219	78,583	-	36,380

Prior to September 1, 2022, transmission constraint penalty factors frequently set prices when PJM modeled a surrogate constraint to limit the dispatch of a generator that would experience voltage instability at its full output due to a transmission outage. Since September 1, 2022, PJM is using a generator output limit constraint to manage generator voltage instability issues. In the first nine months of 2023, there were 19,778 five minute intervals during which PJM reduced the output of generators to manage instability. Changes to the surrogate constraint limit that exceed the unit's ability to reduce output cause constraint violations. Constraint violations also occur when the unit follows the regulation signal or increases its minimum operating parameters above the surrogate constraint limit. Prices set at the $2,000 per MWh penalty factor are not useful signals to the market under these conditions and create false arbitrage opportunities for virtuals.

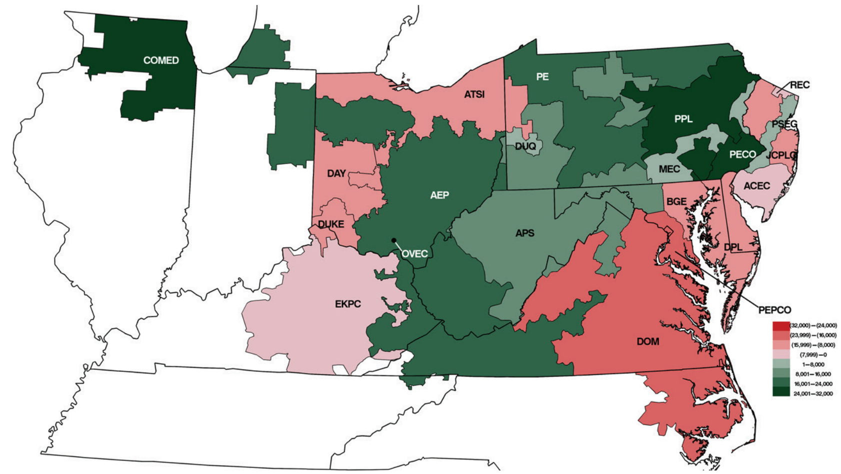
PJM used CT pricing logic until the implementation of fast start pricing on September 1, 2021, to force otherwise uneconomic resources to be marginal and set price in the day-ahead and real-time market solutions. In the event PJM committed a resource that is uneconomic and/or offered with inflexible parameters, PJM used CT pricing logic to model a constraint with a variable flow limit, paired with an artificial override of the inflexible resource's economic minimum, to force the resource to be marginal in the PJM market solution.[106] Frequently, PJM dispatchers also manually overrode the transmission violation penalty factor of the constraint to match the offer price of the resource to artificially control the shadow price of the constraint.

PJM's use of CT pricing logic was inconsistent with the efficient market dispatch and pricing. For that reason, in 2019, FERC declared CT pricing logic to be unjust and unreasonable.[107] PJM continues to use similar methods to artificially change the prices, like using thermal surrogates and forcing units to be marginal. These practices can lead to inefficient market outcomes.

Net Generation by Zone

Figure 3-45 shows the difference between the PJM real-time generation and real-time load by zone for the first nine months of 2023. Figure 3-45 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. Table 3-62 shows the difference between the real-time generation and real-time load by zone for the first nine months of 2022 and 2023.

Figure 3-45 Map of real-time generation less real-time load by zone: January through September, 2023[108]



106 PJM dispatchers generally log the resources paired with a constraint in the CT pricing logic. The data presented is based on PJM dispatcher logs.

107 167 FERC ¶ 61,058 at P 69 (2019).

108 Real-time zonal 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 3-62 Real-time generation less real-time load by zone (GWh): January through September, 2022 and 2023

	Zonal Generation and Load (GWh)					
	2022 (Jan-Sep)			2023 (Jan-Sep)		
Zone	Generation	Load	Net	Generation	Load	Net
ACEC	2,487	7,744	(5,257)	2,016	7,311	(5,295)
AEP	109,538	95,084	14,454	115,331	91,704	23,628
APS	43,897	36,537	7,360	40,037	34,828	5,209
ATSI	43,434	49,669	(6,235)	39,800	47,988	(8,188)
BGE	13,210	23,352	(10,142)	12,551	21,959	(9,408)
COMED	101,028	71,032	29,996	100,158	67,803	32,354
DAY	1,086	12,947	(11,861)	1,093	12,426	(11,333)
DUKE	13,660	20,126	(6,467)	7,037	19,164	(12,128)
DOM	70,631	84,650	(14,019)	71,821	85,319	(13,498)
DPL	4,139	14,237	(10,098)	4,075	13,324	(9,249)
DUQ	13,040	10,021	3,020	11,784	9,720	2,064
EKPC	8,121	9,956	(1,835)	6,592	9,705	(3,113)
JCPLC	7,490	17,129	(9,639)	7,153	16,062	(8,908)
MEC	14,653	11,808	2,845	15,006	11,078	3,929
OVEC	8,594	84	8,510	6,862	87	6,775
PECO	54,553	29,726	24,827	57,632	27,899	29,733
PE	28,580	12,599	15,981	22,369	12,013	10,356
PEPCO	8,299	21,435	(13,137)	7,597	20,328	(12,732)
PPL	51,097	30,830	20,267	52,262	29,145	23,117
PSEG	33,960	32,886	1,074	33,870	31,048	2,822
REC	0	1,106	(1,106)	0	1,048	(1,048)

Net Generation and Load

PJM sums all negative (injections) and positive (withdrawals) at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) 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, power to onsite customers, 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 intervals 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 intervals 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 3-63 shows PJM generation by fuel source in GWh for the first nine months of 2022 and 2023. In the first nine months of 2023, generation from coal units decreased 30.3 percent, generation from natural gas units increased 9.3 percent, and generation from oil increased 23.4 percent compared to the first nine months of 2022. Wind and solar output decreased by 1.1 percent compared to the first nine months of 2022, supplying 4.7 percent of PJM energy in the first nine months of 2023.

Table 3-63 Generation (By fuel source (GWh)): January through September, 2022 and 2023[109 110]

	2022 (Jan-Sep)		2023 (Jan-Sep)		Change in
	GWh	Percent	GWh	Percent	Output
Coal	134,036.7	20.9%	93,380.3	15.0%	(30.3%)
Bituminous	116,483.5	18.2%	83,904.0	13.4%	(28.0%)
Sub Bituminous	12,606.6	2.0%	5,244.9	0.8%	(58.4%)
Other Coal	4,946.6	0.8%	4,231.3	0.7%	(14.5%)
Nuclear	204,420.6	31.9%	204,483.4	32.8%	0.0%
Gas	255,177.6	39.8%	278,661.0	44.7%	9.2%
Natural Gas CC	234,477.8	36.6%	254,586.8	40.8%	8.6%
Natural Gas CT	14,612.7	2.3%	15,926.5	2.6%	9.0%
Natural Gas Other Units	4,944.9	0.8%	7,207.6	1.2%	45.8%
Other Gas	1,142.3	0.2%	940.0	0.2%	(17.7%)
Hydroelectric	12,318.7	1.9%	12,137.9	1.9%	(1.5%)
Pumped Storage	4,933.1	0.8%	4,810.6	0.8%	(2.5%)
Run of River	5,763.5	0.9%	5,845.0	0.9%	1.4%
Other Hydro	1,622.2	0.3%	1,482.3	0.2%	(8.6%)
Wind	21,865.7	3.4%	20,242.9	3.2%	(7.4%)
Waste	3,039.9	0.5%	2,972.7	0.5%	(2.2%)
Oil	1,797.8	0.3%	2,218.0	0.4%	23.4%
Heavy Oil	58.7	0.0%	28.5	0.0%	(51.5%)
Light Oil	436.6	0.1%	843.9	0.1%	93.3%
Diesel	57.6	0.0%	13.6	0.0%	(76.3%)
Other Oil	1,244.8	0.2%	1,331.9	0.2%	7.0%
Solar	7,616.6	1.2%	8,928.1	1.4%	17.2%
Battery	17.4	0.0%	17.8	0.0%	2.4%
Biofuel	1,073.4	0.2%	965.9	0.2%	(10.0%)
Total	641,364.3	100.0%	624,008.1	100.0%	(2.7%)

109 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, power to run pumped hydro pumps or power to charge batteries.
110 Other Gas includes: Landfill, Propane, Butane, Hydrogen, Gasified Coal, and Refinery Gas. Other Coal includes: Lignite, Liquefied Coal, Gasified Coal, and Waste Coal. Other oil includes: Gasoline, Jet Oil, Kerosene, and Petroleum-Other.

Table 3-64 Monthly generation (By fuel source (GWh)): January through September, 2023

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Coal	10,947.5	9,266.3	10,287.5	8,715.9	7,487.0	8,640.6	14,385.8	13,821.7	9,827.9	93,380.3
Bituminous	9,875.7	8,286.1	9,622.4	8,266.6	7,068.3	7,522.7	12,509.0	11,935.2	8,818.1	83,904.0
Sub Bituminous	688.1	473.8	170.0	34.6	94.6	669.5	1,182.7	1,269.3	662.2	5,244.9
Other Coal	383.7	506.3	495.1	414.8	324.2	448.4	694.1	617.2	347.6	4,231.3
Nuclear	24,467.1	21,439.6	21,967.3	20,141.7	22,233.8	23,450.7	24,133.1	23,958.1	22,692.1	204,483.4
Gas	30,707.9	26,980.7	28,592.3	23,550.7	26,427.2	31,895.4	40,190.1	37,961.0	32,355.7	278,661.0
Natural Gas CC	29,603.8	25,862.1	27,390.7	21,194.2	23,657.7	28,716.2	34,806.7	33,900.1	29,455.4	254,586.8
Natural Gas CT	698.5	648.1	724.9	1,660.7	2,069.7	2,271.0	3,468.4	2,592.4	1,792.8	15,926.5
Natural Gas Other Units	291.2	367.5	362.1	592.7	589.5	806.1	1,816.4	1,372.8	1,009.3	7,207.6
Other Gas	114.4	103.0	114.5	103.1	110.3	102.1	98.7	95.7	98.2	940.0
Hydroelectric	1,584.3	1,169.6	1,332.5	1,166.5	1,362.9	1,195.3	1,564.4	1,537.2	1,225.3	12,137.9
Pumped Storage	441.7	390.4	380.7	364.2	484.1	620.6	736.6	753.7	638.7	4,810.6
Run of River	1,011.3	670.9	848.8	704.5	741.2	372.2	557.9	531.7	406.5	5,845.0
Other Hydro	131.3	108.2	103.0	97.9	137.5	202.6	269.9	251.7	180.1	1,482.3
Wind	2,913.7	3,440.9	3,573.9	2,798.6	2,063.6	1,661.9	1,001.0	1,470.5	1,318.7	20,242.9
Waste	322.8	305.2	349.8	323.3	339.6	344.4	350.2	340.9	296.6	2,972.7
Oil	181.4	191.1	235.4	213.3	291.7	243.2	367.9	269.0	225.2	2,218.0
Heavy Oil	0.0	1.8	0.0	0.1	0.0	0.0	9.8	7.4	9.5	28.5
Light Oil	37.9	54.1	102.4	83.6	131.2	94.5	182.6	101.3	56.3	843.9
Diesel	0.1	4.1	0.6	0.1	1.9	2.2	2.2	0.8	1.6	13.6
Other Oil	143.4	131.1	132.4	129.6	158.6	146.4	173.3	159.4	157.8	1,331.9
Solar	417.8	598.4	927.1	1,062.6	1,244.4	1,172.4	1,332.8	1,203.2	969.3	8,928.1
Battery	2.3	1.7	1.9	2.0	1.8	1.9	2.0	1.9	2.3	17.8
Biofuel	119.6	86.1	91.8	90.7	123.2	123.2	95.8	129.9	105.6	965.9
Total	71,664.4	63,479.5	67,359.5	58,065.6	61,575.0	68,729.0	83,423.3	80,693.2	69,018.5	624,008.1

Table 3-65 shows the difference between the day-ahead and the real-time average generation by fuel source.

Table 3-65 Day-ahead and real-time average generation (By fuel source (GWh)): January through September, 2023

	2023 (Jan -Sep)					
	Day-Ahead		Real-Time			Percent
	GWh	Percent	GWh	Percent	Difference	Difference
Coal	93,654.0	15.3%	93,380.3	15.0%	(273.7)	(0.3%)
Bituminous	84,302.7	13.8%	83,904.0	13.4%	(398.7)	(0.5%)
Sub Bituminous	5,362.5	0.9%	5,244.9	0.8%	(117.6)	(2.2%)
Other Coal	3,988.7	0.7%	4,231.3	0.7%	242.6	6.1%
Nuclear	202,599.2	33.1%	204,483.4	32.8%	1,884.3	0.9%
Gas	277,019.6	45.3%	278,661.0	44.7%	1,641.4	0.6%
Natural Gas CC	255,044.3	41.7%	254,586.8	40.8%	(457.4)	(0.2%)
Natural Gas CT	13,924.0	2.3%	15,926.5	2.6%	2,002.5	14.4%
Natural Gas Other Units	7,147.3	1.2%	7,207.6	1.2%	60.3	0.8%
Other Gas	904.0	0.1%	940.0	0.2%	36.0	4.0%
Hydroelectric	11,808.8	1.9%	12,137.9	1.9%	329.1	2.8%
Pumped Storage	5,840.3	1.0%	4,810.6	0.8%	(1,029.7)	(17.6%)
Run of River	5,968.5	1.0%	5,845.0	0.9%	(123.5)	(2.1%)
Other Hydro	0.0	0.0%	1,482.3	0.2%	1,482.3	NA
Wind	14,639.6	2.4%	20,242.9	3.2%	5,603.3	38.3%
Waste	2,923.8	0.5%	2,972.7	0.5%	49.0	1.7%
Oil	2,083.6	0.3%	2,218.0	0.4%	134.5	6.5%
Heavy Oil	18.1	0.0%	28.5	0.0%	10.4	57.2%
Light Oil	772.7	0.1%	843.9	0.1%	71.2	9.2%
Diesel	3.3	0.0%	13.6	0.0%	10.4	316.7%
Other Oil	1,289.4	0.2%	1,331.9	0.2%	42.5	3.3%
Solar	6,105.2	1.0%	8,928.1	1.4%	2,823.0	46.2%
Battery	0.0	0.0%	17.8	0.0%	17.8	NA
Biofuel	995.1	0.2%	965.9	0.2%	(29.1)	(2.9%)
Total	611,828.6	100.0%	624,008.1	100.0%	12,179.4	2.0%

Table 3-66 shows the share of generation by natural gas, coal, nuclear and other fuel types in the real-time energy market since 2008. Generation from natural gas was 44.5 percent, the highest level since the start of PJM markets for the same period, and coal was 15.0 percent, the lowest level since the start of PJM markets for the same period.

Table 3-66 Share of generation by fuel source: January through September, 2008 through 2023

Jan - Sep	Natural Gas	Coal	Nuclear	Other Fuel Type
2008	7.7%	55.0%	34.3%	3.0%
2009	10.7%	50.0%	35.8%	3.6%
2010	11.4%	50.0%	34.3%	4.3%
2011	13.8%	48.2%	33.8%	4.2%
2012	19.7%	41.7%	34.1%	4.5%
2013	16.9%	44.3%	34.5%	4.3%
2014	17.6%	44.2%	33.7%	4.4%
2015	22.6%	38.1%	34.3%	5.0%
2016	27.1%	33.8%	33.9%	5.1%
2017	26.8%	32.2%	35.3%	5.7%
2018	30.7%	29.2%	33.8%	6.4%
2019	36.0%	24.5%	33.2%	6.3%
2020	40.6%	19.0%	33.7%	6.7%
2021	36.8%	24.0%	32.1%	7.2%
2022	39.6%	20.9%	31.8%	7.7%
2023	44.5%	15.0%	32.8%	7.8%

Fuel Diversity

Figure 3-46 shows the fuel diversity index (FDI_e) for PJM energy generation.[111] The FDI_e is defined as $\mathbf{1-\sum_{i=1}^{N} s_i^2}$, 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 3-63 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 30.2 percent from 2012 through the first nine months of 2023. 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 Zones and the increased shares of coal and nuclear that resulted.[112] The increasing trend

111 The MMU 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.

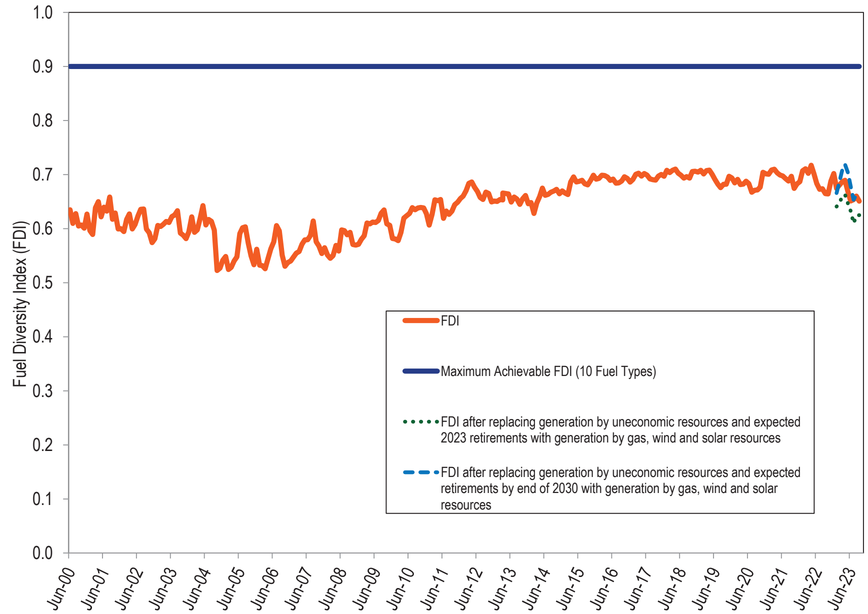
112 See the *2019 Annual State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton Zones occurred in October 2004.

that began in 2008 is a result of decreasing coal generation, increasing gas generation and increasing renewable generation. Coal generation as a share of total generation was 55.0 percent for the first nine months of 2008 and 15.0 percent for the first nine months of 2023. Gas generation as a share of total generation was 7.7 percent for the first nine months of 2008 and 44.7 percent for the first nine months of 2023. Wind and solar generation as a share of total generation was 0.4 percent for the first nine months of 2008 and 4.7 percent for the first nine months of 2023.

The FDI_e decreased 3.7 percent in the first nine months of 2023 compared to the first nine months of 2022.

The FDI_e was also used to measure the impact on fuel diversity of potential retirements in 2023 and through 2030.[113] A total of 8,963 MW of capacity are at risk of retirement in 2023, consisting of 6,086 MW currently planning to retire in 2023 and 2,877 MW expected to retire by the end of 2023 for regulatory reasons. This capacity consists primarily of coal plants and gas peaker units. The units expected to retire by the end of 2023 generated 46,201.8 GWh in the first nine months of 2023. The dashed line (green) in Figure 3-46 shows a counterfactual result for FDI_e assuming the 46,201.8 GWh of generation from uneconomic units and expected 2023 retirements were replaced by gas, wind and solar generation.[114] The FDI_e for the first nine months of 2023 under this counterfactual assumption would have been 4.5 percent lower than the actual FDI_e. A total of 51,757 MW of capacity are at risk of retirement by the end of 2030, consisting of 6,628 MW currently planning to retire, 23,509 MW expected to retire for regulatory reasons, and 21,621 MW expected to be uneconomic. The identified units generated 58,828.6 GWh in the first nine months of 2023. Replacing this generation with gas, wind and solar generation results in a counterfactual FDI_e that is 2.2 percent higher than the actual FDI_e.[115] The dashed line (blue) in Figure 3-46 shows a counterfactual result for FDI_e assuming that this generation is replaced with gas, wind and solar generation.

Figure 3-46 Fuel diversity index for monthly generation: September 2000 through September 2023



Natural Gas Supply Issues

Both pipeline transportation and commodity natural gas are needed to deliver natural gas to power plants. Generators have a number of options which vary by pipeline and market area. A generator could purchase a delivered service in which the seller bundles the transportation and commodity, on a term contract or a spot basis. A generator could purchase pipeline transportation and commodity natural gas separately with a term supply contract or through daily purchases in the spot market. Generators could purchase storage service. Storage services can be bundled with pipeline transportation, or storage and transportation purchased separately to move gas to or from a storage facility.

113 See Units At Risk of Retirement in the *2022Annual State of the Market Report for PJM*, Volume II, Section 7: Net Revenue.

114 It is assumed that 9,313.9 GWh of the replacement energy will be from new wind and solar units. This value represents the increase over 2023 levels in renewable generation that is required by RPS in the first nine months of 2024. The split between solar (75.6 percent) and wind (24.4 percent) is based on queue data and 2023 capacity factors in Table 8-33 and Table 8-36.

115 It is assumed that 50,307.8 GWh of the replacement energy will be from new wind and solar units. This value represents the increase over 2023 levels in renewable generation that is required by RPS in the first nine months of 2030. The split between solar (75.6 percent) and wind (24.4 percent) is based on queue data and 2023 capacity factors in Table 8-33 and Table 8-36.

The storage service will determine the total storage capacity and the injection and withdrawal rights. Storage offers the owner the ability to have on demand supplies, or the ability to redirect unused supplies to storage. Predetermined allocation (PDA) nominations can be used to direct the pipeline as to how to treat an excess or a deficiency of gas at a delivery point. Combinations of these options are also available.

Pipelines build transportation capacity and sell firm capacity to customers. Most of the transportation capacity is sold at tariff rates but in some cases negotiated rates are agreed to. A majority of firm capacity is contracted with gas utilities, gas marketers, industrial customers and generators. The purchasers of firm transportation capacity have the right to resell their capacity. Any such release must be done on the pipeline's electronic bulletin board. Bidders must be approved by the pipeline. When firm capacity on the pipelines is not being used, the pipeline tariffs provide for interruptible service.

In order to be able to actually use the purchased pipeline transportation service, pipelines may enforce nomination deadlines to require generation owners to nominate the flow of gas by defined deadlines. Some pipelines may also impose site specific restrictions that limit the ability of generators to nominate and schedule gas beyond the nomination deadlines. Table 3-67 shows the approved nomination deadlines and corresponding start time of gas flow.[116] Pipelines provide that firm service requests may replace, or bump, interruptible nominations on the pipeline under defined conditions.

Table 3-67 Approved nomination deadlines

	Nomination Cycle	Nom Deadline (EPT)	Time of Flow (EPT)	Bumping	Hours left in gas day for supply to flow
Day Before Flow	Timely	1400	1000		24
Day Before Flow	Evening	1900	1000	Yes	24
Day of Flow	Intraday 1	1100	1500	Yes	19
Day of Flow	Intraday 2	1530	1900	Yes	15
Day of Flow	Intraday 3	2000	2300	No	11

In 2022 and the first nine months of 2023, some interstate gas pipelines that provide service in the PJM service territory issued notices limiting the flexibility of firm and nonfirm transportation services. These notices include alerts, constraints, warnings of operational flow orders (OFO) and actual OFOs. These notices generally permit the pipelines to enforce nomination deadlines and to restrict the provision of gas to 24 hour ratable takes, meaning that nominations must be the same for each hour in the gas day. Pipelines may also enforce strict balancing constraints which limit the ability of gas users to deviate from the 24 hour ratable take and which may limit the ability of users to have access to unused gas. The pipelines providing service in the PJM service territory that issued notices were: ANR Pipeline, Columbia Gas Transmission, Cove Point, East Tennessee Natural Gas, Eastern Gas Transmission & Storage, Eastern Shore, Equitrans Transmission, Horizon Pipeline, Natural Gas Pipeline, Northern Border Pipeline, Panhandle Eastern, Rockies Express, Texas Eastern, Tennessee Gas Pipeline and Transcontinental Gas Pipeline.

Pipeline operators use restrictive and inflexible rules to manage the balance of supply and demand during constrained operating conditions determined by the pipeline. The independent operations of geographically overlapping pipelines during extreme conditions highlights the shortcomings of a gas pipeline network that relies on individual pipelines to manage the balancing of total supply and demand across a broad geographical area that includes multiple pipelines. The independent operational restrictions imposed by pipelines and the impact on electric generators during extreme conditions demonstrate 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.

The increase in natural gas fired capacity in PJM, and the expected further increase, has highlighted issues with the dependence of PJM system reliability on the fuel transportation arrangements entered into by generators. The risks to the fuel supply for gas generators, including the risk of interruptible supply on cold days and the ability to get gas on short notice during times of critical pipeline operations, create risks for the bulk power system.

In general, the availability status of gas generators in the PJM energy market does not accurately reflect their ability to procure and nominate gas on the pipelines based on the rules defined by the pipelines. If the result of the

116 Nomination deadlines approved in FERC Order No. 809, implemented April 1, 2016.

pipeline rules is that some gas generators cannot reliably procure gas during the operating day in order to respond to PJM directions to generate, the result could be an inflated estimate of reserves on the PJM system, if the generator does not have back up fuel. Gas units should be required to be on forced outage if they cannot obtain gas during the operating day to meet their must offer requirement.

PJM requires real-time situational awareness of the availability of all generators, including gas-fired generators, during the operating day, in order to operate the system effectively including knowledge of the level of available reserves. The MMU recommends: that gas generators be required to confirm, regularly during the operating day, that they can obtain gas if requested to operate at their economic maximum level; that gas generators provide that information to PJM during the operating day; and that gas generators be required to be on forced outage if they cannot obtain gas during the operating day to meet their must offer requirement as a result of pipeline restrictions, and they do not have backup fuel. As part of this, the MMU recommends that PJM collect data on each individual generator's fuel supply arrangements at least annually or when such arrangements change, and analyze the associated locational and regional risks to reliability.

Notification time is the period between PJM's notification and the beginning of the start sequence for a generating resource. Combustion turbines normally have notification times between six and 30 minutes. When pipelines require generators to nominate gas per the NAESB deadlines, generators must nominate gas well in advance and cannot start in six or 30 minutes. Instead, generators need significant more time to nominate gas. This increase in the time needed should be requested and reflected in the units' notification time.

For example, the last nomination cycle available per NAESB is intraday 3 (ID3), see Table 3-67. The ID3 deadline is 20:00 EPT for gas that starts flowing at 23:00 (in three hours). The previous cycle, intraday 2 (ID2) deadline is at 15:30 EPT for gas that starts flowing at 19:00. A generator that has not nominated gas by ID2 cannot start until 23:00. Therefore, at 19:00, the unit has an implied time to start of four hours. Four hours is equal to 23:00 (the earliest the unit can start) minus 19:00. Table 3-68 shows the notification time gas fired generators should be requesting and submitting when pipelines require nominating per the NAESB cycle deadlines.

Table 3-68 Generator notification times when pipeline NAESB cycle deadlines are imposed

Hour	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12
Notification Time	15	14	13	12	11	10	9	8	7	6	9	8
Time On (If Called)	15:00	15:00	15:00	15:00	15:00	15:00	15:00	15:00	15:00	15:00	19:00	19:00
Nearest Cycle	ID1	ID1	ID1	ID1	ID1	ID1	ID1	ID1	ID1	ID1	ID2	ID2

Hour	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Notification Time	7	6	9	8	7	6	5	20	19	18	17	16
Time On (If Called)	19:00	19:00	23:00	23:00	23:00	23:00	23:00	15:00	15:00	15:00	15:00	15:00
Nearest Cycle	ID2	ID2	ID3	ID3	ID3	ID3	ID3	ID1	ID1	ID1	ID1	ID1

The MMU has proposed enhancements for situational awareness and transparency to improve the scheduling problem that PJM and gas fired units face, addressing how to reflect pipeline constraints in generator operating parameters, including how generators should submit notification times, and minimum run times and request temporary parameter exceptions.[117] The resultant guidelines were posted by the MMU and PJM on September 8, 2023.[118]

Types 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 3-69 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

117 "Gas Nomination Cycles and Units Operating Parameters," Electric Gas Coordination Senior Task Force (EGCSTF), August 15, 2023.
118 *See* Guidelines posted by the MMU and PJM: Temporary Operating Parameter Limit (PLS) Exceptions due to Pipeline Restrictions. <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Temporary_Operating_Parameter_Limit_(PLS)_Exceptions_due_to_Pipeline_Restrictions_20230908.pdf>

months of 2023, coal units were 9.3 percent and natural gas units were 84.3 percent of marginal resources. In the first nine months of 2023, natural gas combined cycle units were 71.2 percent of marginal resources. In the first nine months of 2022, coal units were 10.4 percent and natural gas units were 74.3 percent of the total marginal resources. In the first nine months of 2022, natural gas combined cycle units were 60.4 percent of the total marginal resources. In the first nine months of 2023, 55.3 percent of the wind marginal units had negative offer prices, 43.7 percent had zero offer prices and 1.0 percent of the wind marginal units had positive offer prices. In the first nine months of 2022, 55.8 percent of the wind marginal units had negative offer prices, 39.1 percent had zero offer prices and 5.1 percent had positive offer prices.

The proportion of marginal nuclear units increased from 0.45 percent in the first nine months of 2022 to 0.51 percent in the first nine months of 2023. 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.

PJM implemented fast start pricing on September 1, 2021. The marginal resources shown in Table 3-69 are from the pricing run, which may not be the same as marginal resources from the dispatch run.

Table 3-69 Type of fuel used and technology (By real-time marginal units): January through September, 2019 through 2023[119]

		(Jan - Sep)				
Fuel	Technology	2019	2020	2021	2022	2023
Gas	CC	60.79%	66.03%	60.86%	60.40%	71.16%
Gas	CT	6.38%	5.74%	8.52%	11.53%	10.24%
Coal	Steam	26.32%	17.30%	16.90%	10.73%	9.26%
Wind	Wind	2.92%	5.64%	8.93%	10.86%	4.75%
Gas	Steam	1.28%	1.84%	1.07%	1.46%	1.78%
Gas	RICE	0.00%	0.30%	0.53%	0.87%	1.15%
Oil	CT	0.47%	1.11%	1.06%	2.61%	0.52%
Uranium	Steam	1.17%	1.46%	0.81%	0.45%	0.51%
Oil	CC	0.02%	0.00%	0.03%	0.04%	0.27%
Municipal Waste	Steam	0.02%	0.01%	0.01%	0.03%	0.10%
Oil	Steam	0.03%	0.07%	0.09%	0.02%	0.07%
Oil	RICE	0.00%	0.03%	0.05%	0.04%	0.07%
Municipal Waste	RICE	0.00%	0.00%	0.00%	0.00%	0.06%
Other	Steam	0.07%	0.04%	0.10%	0.05%	0.05%
Other	Solar	0.08%	0.40%	1.04%	0.90%	0.01%
Landfill Gas	CT	0.01%	0.01%	0.01%	0.00%	0.00%
Municipal Waste	CT	0.00%	0.00%	0.00%	0.00%	0.00%
Landfill Gas	Steam	0.00%	0.00%	0.00%	0.00%	0.00%
Gas	Fuel Cell	0.00%	0.00%	0.00%	0.00%	0.00%
Landfill Gas	RICE	0.00%	0.00%	0.00%	0.00%	0.00%

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

Figure 3-47 shows the type of fuel used by marginal resources in the real-time energy market for the first nine months of every year since 2004. The role of coal as a marginal resource has declined while the role of gas as a marginal resource has increased.

Figure 3-47 Type of fuel used (By real-time marginal units): January through September, 2004 through 2023

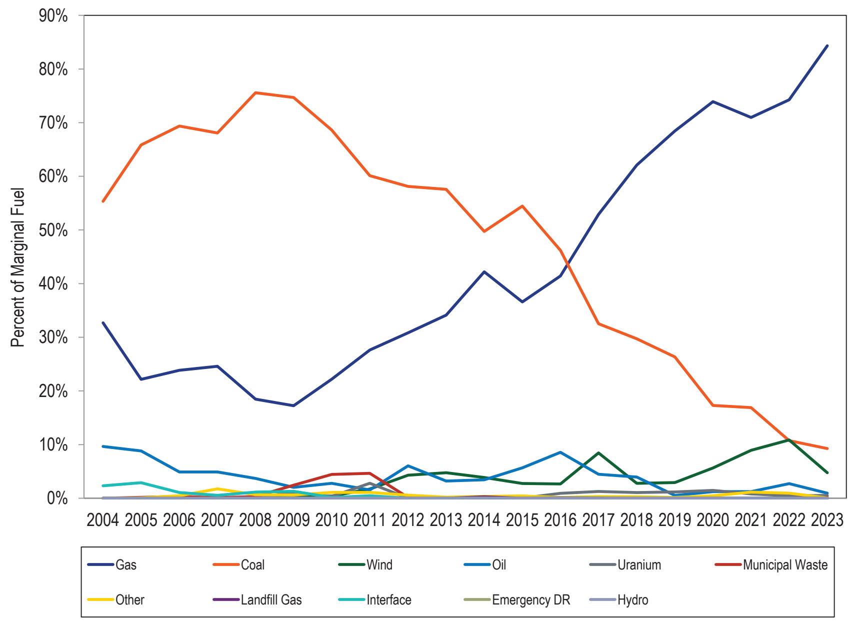


Table 3-70 shows the type of fuel and technology by fast start marginal resources and other marginal resources in the real-time energy market in the first nine months of 2023. In the first nine months of 2023, marginal fast start resources accounted for 6.25 percent of all marginal resources in the pricing run.

Table 3-70 Fuel type and technology (Real-time marginal units and fast start marginal units): January through September, 2023

		2023 (Jan - Sep)		
Fuel	Technology	Fast Start	Other	Both
Coal	Steam	0.00%	9.26%	9.26%
Gas	CC	0.00%	71.16%	71.16%
Gas	CT	4.64%	5.60%	10.24%
Gas	RICE	1.14%	0.01%	1.15%
Gas	Steam	0.00%	1.78%	1.78%
Landfill Gas	CT	0.00%	0.00%	0.00%
Municipal Waste	RICE	0.02%	0.04%	0.06%
Municipal Waste	Steam	0.00%	0.10%	0.10%
Oil	CC	0.00%	0.27%	0.27%
Oil	CT	0.35%	0.18%	0.52%
Oil	RICE	0.07%	0.00%	0.07%
Oil	Steam	0.00%	0.07%	0.07%
Other	Solar	0.00%	0.01%	0.01%
Other	Steam	0.00%	0.05%	0.05%
Uranium	Steam	0.00%	0.51%	0.51%
Wind	Wind	0.04%	4.71%	4.75%
All Marginal Units		6.25%	93.75%	100.00%

Table 3-71 shows the fuel used and technology where relevant, of marginal resources in the day-ahead energy market.[120]

UTCs' share of marginal resources increased from 40.6 percent in the first nine months of 2022 to 53.8 percent in the first nine months of 2023. Virtual transactions' share of marginal resources increased from 81.8 percent in the first nine months of 2022 to 86.5 percent in the first nine months of 2023.

120 The dispatch run marginal resource and sensitivity factor data is used to calculate the results in the day-ahead market for January 2022 through March 2023 due to the inaccuracy of the sensitivity factor data in the pricing run even though PJM uses LMPs generated in the pricing run as settlement LMPs.

Table 3-71 Day-ahead marginal resources by type/fuel used and technology: January through September, 2019 through 2023

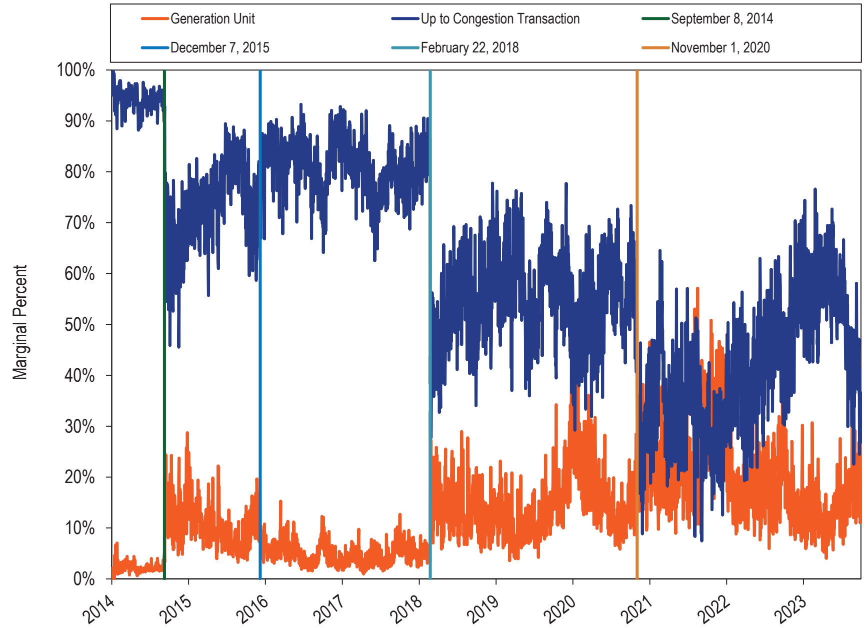
		(Jan - Sep)				
Type/Fuel	Technology	2019	2020	2021	2022	2023
Up to Congestion Transaction	NA	57.70%	53.81%	36.14%	40.62%	53.83%
DEC	NA	18.41%	17.64%	26.50%	22.26%	18.00%
INC	NA	12.86%	12.41%	17.30%	18.93%	14.68%
Gas	CC	5.92%	9.90%	11.62%	11.51%	7.96%
Coal	Steam	4.23%	4.83%	6.32%	4.26%	3.06%
Wind	Wind	0.10%	0.24%	0.68%	1.08%	0.88%
Gas	Steam	0.39%	0.40%	0.52%	0.54%	0.65%
Gas	CT	0.10%	0.24%	0.24%	0.18%	0.30%
Dispatchable Transaction	NA	0.10%	0.08%	0.27%	0.23%	0.17%
Other	Solar	0.02%	0.01%	0.05%	0.08%	0.17%
Price Sensitive Demand	NA	0.00%	0.00%	0.05%	0.08%	0.07%
Gas	RICE	0.04%	0.05%	0.12%	0.03%	0.06%
Water	Hydro	0.00%	0.00%	0.00%	0.00%	0.06%
Oil	Steam	0.01%	0.01%	0.02%	0.01%	0.05%
Uranium	Steam	0.06%	0.23%	0.03%	0.00%	0.03%
Oil	CT	0.04%	0.09%	0.06%	0.15%	0.02%
Oil	CC	0.00%	0.00%	0.01%	0.01%	0.00%
Other	Steam	0.01%	0.05%	0.03%	0.01%	0.00%
Municipal Waste	RICE	0.01%	0.01%	0.03%	0.01%	0.00%
Oil	RICE	0.00%	0.00%	0.01%	0.01%	0.00%
Municipal Waste	Steam	0.00%	0.00%	0.00%	0.00%	0.00%
Total		100.00%	100.00%	100.00%	100.00%	100.00%

Figure 3-48 shows, for the day-ahead energy market from January 2014 through September 2023, the daily proportion of marginal resources that were up to congestion transactions or generation units.[121]

Up to congestion transaction volumes decreased following the allocation of uplift charges on November 1, 2020, but increased in 2022.[122] The hourly average submitted up to congestion bid MW increased by 121.5 percent and cleared up to congestion bid MW increased by 104.4 percent in the first nine months of 2023 compared to the first nine months of 2022, although the submitted and cleared volumes peaked in April 2023 and declined significantly through September 2023.

121 The dispatch run marginal resource and sensitivity factor data is used to calculate the results in the day-ahead market for January 2022 through March 2023 due to the inaccuracy of the sensitivity factor data in the pricing run even though PJM uses LMPs generated in the pricing run as settlement LMPs.
122 172 FERC ¶ 61,046 (2020).

Figure 3-48 Day-ahead marginal up to congestion transaction and generation units: January 2014 through September 2023

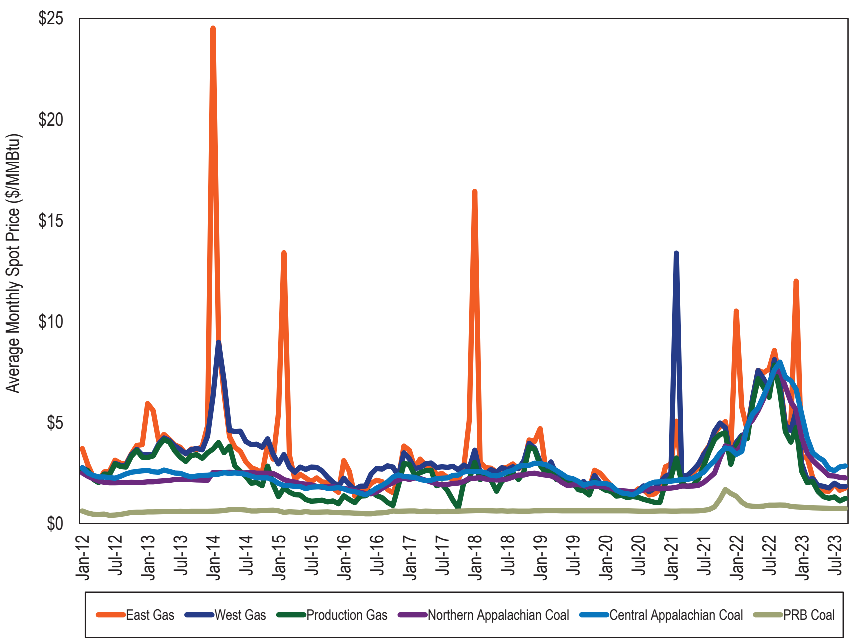


Fuel Price Trends and LMP

In a competitive market, changes in LMP 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. Changes in emission allowance costs also contribute to changes in the marginal cost of marginal units.

Figure 3-49 shows fuel prices in PJM for 2012 through September 2023. Natural gas prices, coal prices, and oil prices decreased in the first nine months of 2023 compared to the first nine months of 2022. The price of natural gas in the Marcellus Shale production area is lower than in other areas of PJM and a number of new combined cycle plants have located in the production area since 2016. In the first nine months of 2023, the price of production gas was 72.4 percent lower than in the first nine months of 2022, the price of eastern natural gas was 70.6 percent lower and the price of western natural gas was 66.5 percent lower. The price of Northern Appalachian coal was 49.8 percent lower; the price of Central Appalachian coal was 41.1 percent lower; and the price of Powder River Basin coal was 19.5 percent lower.[123] The price of ULSD NY Harbor Barge was 32.3 percent lower in the first nine months of 2023 than in the first nine months of 2022.

Figure 3-49 Spot average fuel price comparison: 2012 through September 2023 ($/MMBtu)



123 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.

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 up to fourteen 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, Maryland, New Jersey, and Virginia.[124] 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 reserves. 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. The component, ancillary service redispatch cost, shows the contribution of this cost to the PJM's load weighted LMP. In addition, in periods when the SCED solution does not meet the reserve requirements, PJM should invoke shortage pricing, but only if there is a well defined operating reserve demand curve. During shortage conditions, the LMPs of marginal generators reflect the cost of not meeting the reserve

124 New Jersey withdrew from RGGI, effective January 1, 2012, and rejoined RGGI effective January 1, 2020. Virginia joined RGGI effective January 1, 2021.

requirements, the scarcity component, which is defined by the operating reserve demand curve.[125]

Starting on September 1, 2021, the components shown in Table 3-72 and Table 3-74 are from the pricing run which includes the impact of amortized start cost and amortized no load cost of the fast start marginal units. The components of LMP are shown in Table 3-72, including markup using unadjusted cost-based offers.[126] Table 3-72 shows that in the first nine months of 2023, 15.2 percent of the load-weighted LMP was the result of coal costs, 43.7 percent was the result of gas costs and 6.1 percent was the result of the cost of carbon emission allowances. Using unadjusted cost-based offers, negative markup was -8.7 percent of the load-weighted LMP. Using unadjusted cost-based offers, positive markup was 11.2 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. LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no cheaper 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. In the first nine months of 2023, 4.6 percent of the load-weighted LMP was the result of transmission penalty factors affecting LMPs. The percent contribution of transmission penalty factors has increased substantially since PJM removed the constraint relaxation logic and allowed penalty factors to affect LMPs starting in February 2019. The component NA is the unexplained portion of load-weighted LMP. For several intervals, PJM failed 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 NA component is the cumulative effect of excluding those five minute intervals. The percent column is the difference (in percentage points) in the proportion of LMP represented by each component in the first nine months of 2022 and 2023.

125 Scarcity component includes ancillary service redispatch cost component during periods of scarcity.
126 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 3-72 Components of real-time (Unadjusted) load-weighted average LMP: January through September, 2022 and 2023

	2022 (Jan - Sep)		2023 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$42.55	54.7%	$13.48	43.7%	(11.0%)
Coal	$5.94	7.6%	$4.69	15.2%	7.6%
Positive Markup	$7.37	9.5%	$3.44	11.2%	1.7%
Variable Maintenance	$2.40	3.1%	$2.35	7.6%	4.5%
Ten Percent Adder	$4.88	6.3%	$1.94	6.3%	0.0%
CO_2 Cost	$1.75	2.2%	$1.87	6.1%	3.8%
Transmission Constraint Penalty Factor	$4.46	5.7%	$1.42	4.6%	(1.1%)
Variable Operations	$0.94	1.2%	$1.09	3.5%	2.3%
Opportunity Cost Adder	$1.81	2.3%	$0.73	2.4%	0.0%
NO_x Cost	$2.85	3.7%	$0.70	2.3%	(1.4%)
LPA Rounding Difference	$0.63	0.8%	$0.42	1.3%	0.5%
Oil	$0.82	1.1%	$0.38	1.2%	0.2%
Ancillary Service Redispatch Cost	$1.77	2.3%	$0.37	1.2%	(1.1%)
Market-to-Market	$1.97	2.5%	$0.29	0.9%	(1.6%)
NA	$0.25	0.3%	$0.20	0.6%	0.3%
Increase Generation Differential	$0.21	0.3%	$0.11	0.3%	0.1%
Scarcity	$1.52	2.0%	$0.07	0.2%	(1.7%)
Landfill Gas	$0.02	0.0%	$0.05	0.2%	0.1%
Other	$0.02	0.0%	$0.02	0.1%	0.1%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	0.0%
LPA-SCED Differential	($0.01)	(0.0%)	($0.00)	(0.0%)	0.0%
Decrease Generation Differential	($0.04)	(0.1%)	($0.01)	(0.0%)	0.0%
Renewable Energy Credits	($0.36)	(0.5%)	($0.08)	(0.3%)	0.2%
Negative Markup	($3.90)	(5.0%)	($2.68)	(8.7%)	(3.7%)
Total	$77.84	100.0%	$30.87	100.0%	0.0%

Change in Components of LMP

Table 3-73 shows the components of the decrease in real-time load-weighted average LMP from the first nine months of 2022 to the first nine months of 2023. In the first nine months of 2023, the real-time load-weighted average LMP decreased by $46.97 per MWh, 60.3 percent. Most of the decrease, 65.1 percent of the decrease in LMP, was the result of the $30.57 per MWh decrease in the fuel and consumables cost components of LMP (the sum of gas, coal, oil, landfill gas, variable operations). The emissions cost components of LMP (the sum of NO_X, CO_2, opportunity cost adder, SO_2, and renewable energy credits) decreased the LMP by $2.82 per MWh, 6.0 percent of the decrease in LMP. The sum of the positive and negative markups, ten percent adder, and maintenance cost components, all of which reflect market power, decreased the LMP $5.70 per MWh, 12.1 percent of the decrease in LMP. The scarcity component decreased the LMP by $1.45 per MWh, 3.1 percent of the decrease in the LMP. The transmission constraint penalty factor decreased the LMP by $3.04 per MWh, 6.5 percent. The ancillary service redispatch cost, the opportunity cost of reduced marginal generation to meet reserve requirements, decreased the LMP by $1.40 per MWh, 3.0 percent.

Table 3-73 Components of change in real-time load-weighted average LMP: January through September, 2023

Component	2022 (Jan - Sep)	2023 (Jan - Sep)	Change in LMP	Percent
Fuel and Consumables	$50.26	$19.69	($30.57)	65.1%
Emission Related	$6.05	$3.23	($2.82)	6.0%
Market Power Related	$10.75	$5.06	($5.70)	12.1%
Scarcity	$1.52	$0.07	($1.45)	3.1%
Transmission Constraint Penalty Factor	$4.46	$1.42	($3.04)	6.5%
Ancillary Service Redispatch Cost	$1.77	$0.37	($1.40)	3.0%
Emergency Demand Response	$0.00	$0.00	$0.00	0.0%
PJM Administrative Cap	$0.00	$0.00	$0.00	0.0%
All Other	$3.02	$1.03	($1.99)	4.2%
Total	$77.84	$30.87	($46.97)	100.0%

In order to understand the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach (Table 3-72 and Table 3-77) markup is the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-74 and Table 3-78), 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 3-74, including markup using adjusted cost-based offers.

Table 3-74 Components of real-time (Adjusted) load-weighted average LMP: January through September, 2022 and 2023

	2022 (Jan - Sep)		2023 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$42.55	54.7%	$13.48	43.7%	(11.0%)
Coal	$5.94	7.6%	$4.69	15.2%	7.6%
Positive Markup	$10.28	13.2%	$4.44	14.4%	1.2%
Variable Maintenance	$2.40	3.1%	$2.35	7.6%	4.5%
CO_2 Cost	$1.75	2.2%	$1.87	6.1%	3.8%
Transmission Constraint Penalty Factor	$4.46	5.7%	$1.42	4.6%	(1.1%)
Variable Operations	$0.94	1.2%	$1.09	3.5%	2.3%
Opportunity Cost Adder	$1.81	2.3%	$0.73	2.4%	0.0%
NO_x Cost	$2.85	3.7%	$0.70	2.3%	(1.4%)
LPA Rounding Difference	$0.63	0.8%	$0.42	1.3%	0.5%
Oil	$0.82	1.1%	$0.38	1.2%	0.2%
Ancillary Service Redispatch Cost	$1.77	2.3%	$0.37	1.2%	(1.1%)
Market-to-Market	$1.97	2.5%	$0.29	0.9%	(1.6%)
NA	$0.25	0.3%	$0.20	0.6%	0.3%
Increase Generation Differential	$0.21	0.3%	$0.11	0.3%	0.1%
Scarcity	$1.52	2.0%	$0.07	0.2%	(1.7%)
Landfill Gas	$0.02	0.0%	$0.05	0.2%	0.1%
Other	$0.02	0.0%	$0.02	0.1%	0.1%
Ten Percent Adder	$0.00	0.0%	$0.01	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	0.0%
LPA-SCED Differential	($0.01)	(0.0%)	($0.00)	(0.0%)	0.0%
Decrease Generation Differential	($0.04)	(0.1%)	($0.01)	(0.0%)	0.0%
Renewable Energy Credits	($0.36)	(0.5%)	($0.08)	(0.3%)	0.2%
Negative Markup	($1.94)	(2.5%)	($1.74)	(5.6%)	(3.2%)
Total	$77.84	100.0%	$30.87	100.0%	0.0%

PJM implemented fast start pricing on September 1, 2021. The commitment cost related components of LMP are shown in Table 3-75 including markup using unadjusted cost-based offers for the first nine months of 2023. In the first nine months of 2023, 2.4 percent of the load-weighted average LMP was the result of commitment costs. The majority of the commitment costs in LMP were fuel costs in the no load component of offers for gas fired fast start units. The second largest component was maintenance costs.

Table 3-75 Commitment cost related components of real-time (Unadjusted) load-weighted average LMP: January through September, 2023

	Start Cost Components		No Load Components		Other Components		Total	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent
Gas	$0.00	0.0%	$0.42	1.4%	$13.06	42.3%	$13.48	43.7%
Coal	$0.00	0.0%	$0.00	0.0%	$4.69	15.2%	$4.69	15.2%
Postive Markup	$0.04	0.1%	$0.00	0.0%	$3.40	11.0%	$3.44	11.2%
Variable Maintenance	$0.11	0.3%	$0.11	0.4%	$2.14	6.9%	$2.35	7.6%
Ten Percent Adder	$0.01	0.0%	$0.04	0.1%	$1.90	6.1%	$1.94	6.3%
CO_2 Cost	$0.00	0.0%	$0.02	0.1%	$1.86	6.0%	$1.87	6.1%
Transmission Constraint Penalty Factor	$0.00	0.0%	$0.00	0.0%	$1.42	4.6%	$1.42	4.6%
Variable Operations	$0.00	0.0%	$0.00	0.0%	$1.09	3.5%	$1.09	3.5%
Opportunity Cost Adder	$0.00	0.0%	$0.00	0.0%	$0.73	2.4%	$0.73	2.4%
NO_x Cost	$0.00	0.0%	$0.03	0.1%	$0.67	2.2%	$0.70	2.3%
LPA Rounding Difference	$0.00	0.0%	$0.00	0.0%	$0.42	1.3%	$0.42	1.3%
Oil	$0.00	0.0%	$0.02	0.1%	$0.37	1.2%	$0.38	1.2%
Ancillary Service Redispatch Cost	$0.00	0.0%	$0.00	0.0%	$0.37	1.2%	$0.37	1.2%
Market-to-Market	$0.00	0.0%	$0.00	0.0%	$0.29	0.9%	$0.29	0.9%
NA	$0.00	0.0%	$0.00	0.0%	$0.20	0.6%	$0.20	0.6%
Increase Generation Differential	$0.00	0.0%	$0.00	0.0%	$0.11	0.3%	$0.11	0.3%
Scarcity	$0.00	0.0%	$0.00	0.0%	$0.07	0.2%	$0.07	0.2%
Landfill Gas	$0.00	0.0%	$0.00	0.0%	$0.05	0.2%	$0.05	0.2%
Other	$0.00	0.0%	$0.00	0.0%	$0.02	0.1%	$0.02	0.1%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
LPA-SCED Differential	$0.00	0.0%	$0.00	0.0%	($0.00)	(0.0%)	($0.00)	(0.0%)
Decrease Generation Differential	$0.00	0.0%	$0.00	0.0%	($0.01)	(0.0%)	($0.01)	(0.0%)
Renewable Energy Credits	$0.00	0.0%	$0.00	0.0%	($0.08)	(0.3%)	($0.08)	(0.3%)
Negative Markup	($0.03)	(0.1%)	($0.03)	(0.1%)	($2.62)	(8.5%)	($2.68)	(8.7%)
Total	$0.13	0.4%	$0.60	1.9%	$30.14	97.6%	$30.87	100.0%

The components of LMP for the dispatch run and the pricing run are shown in Table 3-76, including markup using unadjusted cost-based offers for the first nine months of 2023.

Table 3-76 Comparison of components of real-time (Unadjusted) load-weighted average LMP in the dispatch run and pricing run: January through September, 2023

	Dispatch		Pricing		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$12.65	43.4%	$13.48	43.7%	0.2%
Coal	$5.08	17.4%	$4.69	15.2%	(2.3%)
Positive Markup	$3.02	10.4%	$3.44	11.2%	0.8%
Variable Maintenance	$1.86	6.4%	$2.35	7.6%	1.2%
Ten Percent Adder	$1.88	6.5%	$1.94	6.3%	(0.2%)
CO_2 Cost	$1.90	6.5%	$1.87	6.1%	(0.4%)
Transmission Constraint Penalty Factor	$1.51	5.2%	$1.42	4.6%	(0.6%)
Variable Operations	$1.09	3.7%	$1.09	3.5%	(0.2%)
Opportunity Cost Adder	$0.68	2.3%	$0.73	2.4%	0.0%
NO_x Cost	$0.75	2.6%	$0.70	2.3%	(0.3%)
LPA Rounding Difference	$0.36	1.2%	$0.42	1.3%	0.1%
Oil	$0.40	1.4%	$0.38	1.2%	(0.1%)
Ancillary Service Redispatch Cost	$0.29	1.0%	$0.37	1.2%	0.2%
Market-to-Market	$0.21	0.7%	$0.29	0.9%	0.2%
NA	$0.11	0.4%	$0.20	0.6%	0.3%
Increase Generation Differential	$0.14	0.5%	$0.11	0.3%	(0.1%)
Scarcity	$0.08	0.3%	$0.07	0.2%	(0.0%)
Landfill Gas	$0.03	0.1%	$0.05	0.2%	0.0%
Other	$0.02	0.1%	$0.02	0.1%	(0.0%)
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
LPA-SCED Differential	($0.00)	(0.0%)	($0.00)	(0.0%)	0.0%
Decrease Generation Differential	($0.01)	(0.0%)	($0.01)	(0.0%)	0.0%
Renewable Energy Credits	($0.06)	(0.2%)	($0.08)	(0.3%)	(0.1%)
Negative Markup	($2.86)	(9.8%)	($2.68)	(8.7%)	1.2%
Total	$29.14	100.0%	$30.87	100.0%	0.0%

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, 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.

Table 3-77 shows the components of the PJM day-ahead annual load-weighted average LMP. In the first nine months of 2023, 15.6 percent of the load-weighted LMP was the result of gas costs, 17.1 percent of the load-weighted LMP was the result of coal costs, 18.9 percent was the result of INCs, 26.0 percent was the result of DECs, 3.8 percent was the result of UTCs, and 8.2 percent was the result of positive markup.[127]

Table 3-77 Components of day-ahead (Unadjusted) load-weighted average LMP (Dollars per MWh): January through September, 2022 and 2023

	2022 (Jan - Sep)		2023 (Jan - Sep)		
Component	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
DEC	$23.54	30.6%	$8.29	26.0%	(4.6%)
INC	$16.44	21.4%	$6.01	18.9%	(2.5%)
Coal	$6.51	8.5%	$5.44	17.1%	8.6%
Gas	$15.30	19.9%	$4.98	15.6%	(4.3%)
Positive Markup	$5.42	7.1%	$2.62	8.2%	1.2%
Up to Congestion Transaction	$2.24	2.9%	$1.20	3.8%	0.8%
Ten Percent Adder	$2.03	2.6%	$1.02	3.2%	0.6%
Variable Operations	$0.66	0.9%	$0.96	3.0%	2.2%
CO_2	$1.04	1.4%	$0.92	2.9%	1.5%
Variable Maintenance	$0.70	0.9%	$0.76	2.4%	1.5%
Dispatchable Transaction	$1.17	1.5%	$0.49	1.5%	0.0%
NO_x	$1.46	1.9%	$0.43	1.4%	(0.5%)
Oil	$0.05	0.1%	$0.19	0.6%	0.5%
Opportunity Cost Adder	$0.02	0.0%	$0.09	0.3%	0.3%
Price Sensitive Demand	$0.38	0.5%	$0.09	0.3%	(0.2%)
Other	$0.00	0.0%	$0.01	0.0%	0.0%
SO_2	$0.00	0.0%	$0.00	0.0%	0.0%
Negative Markup	($1.17)	(1.5%)	($1.67)	(5.3%)	(3.7%)
Municipal Waste	$0.01	0.0%	$0.00	0.0%	(0.0%)
NA	$1.00	1.3%	$0.02	0.1%	(1.2%)
Total	$76.81	100.0%	$31.86	100.0%	0.0%

127 The dispatch run marginal resource and sensitivity factor data is used to calculate the results in the day-ahead market for January 2022 through September 2023 due to the inaccuracy of the sensitivity factor data in the pricing run even though PJM uses LMPs generated in the pricing run as settlement LMPs.

Table 3-78 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 and oil units.[128]

Table 3-78 Components of day-ahead (Adjusted) load-weighted average LMP (Dollars per MWh): January through September, 2022 and 2023

	2022 (Jan - Sep)		2023 (Jan- Sep)		
Component	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
DEC	$23.54	30.6%	$8.29	26.0%	(4.6%)
INC	$16.44	21.4%	$6.01	18.9%	(2.5%)
Coal	$6.51	8.5%	$5.44	17.1%	8.6%
Gas	$15.30	19.9%	$4.98	15.6%	(4.3%)
Positive Markup	$6.71	8.7%	$3.10	9.7%	1.0%
Up to Congestion Transaction	$2.24	2.9%	$1.20	3.8%	0.8%
Variable Operations	$0.66	0.9%	$0.96	3.0%	2.2%
CO_2	$1.04	1.4%	$0.92	2.9%	1.5%
Variable Maintenance	$0.70	0.9%	$0.76	2.4%	1.5%
Dispatchable Transaction	$1.17	1.5%	$0.49	1.5%	0.0%
NO_x	$1.46	1.9%	$0.43	1.4%	(0.5%)
Oil	$0.05	0.1%	$0.19	0.6%	0.5%
Opportunity Cost Adder	$0.02	0.0%	$0.09	0.3%	0.3%
Price Sensitive Demand	$0.38	0.5%	$0.09	0.3%	(0.2%)
Other	$0.00	0.0%	$0.01	0.0%	0.0%
Ten Percent Adder	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2	$0.00	0.0%	$0.00	0.0%	0.0%
Negative Markup	($0.43)	(0.6%)	($1.14)	(3.6%)	(3.0%)
Municipal Waste	$0.01	0.0%	$0.00	0.0%	(0.0%)
NA	$1.00	1.3%	$0.02	0.1%	(1.2%)
Total	$76.81	100.0%	$31.86	100.0%	0.0%

Table 3-79 shows the change in the components of day-ahead load-weighted average LMP from the first nine months of 2022 to the first nine months of 2023. In the first nine months of 2023, the day-ahead load-weighted average LMP decreased by $44.95 per MWh.

Table 3-79 Components of change in day-ahead load-weighted average LMP: January through September, 2022 and 2023

Component	2022 (Jan - Sep)	2023 (Jan - Sep)	Change in LMP	Percent
Virtuals	$42.22	$15.50	($26.73)	59.5%
Fuel and Consumables	$21.86	$10.62	($11.24)	25.0%
Market Power Related	$7.64	$3.69	($3.95)	8.8%
Emission Related	$2.50	$1.35	($1.14)	2.5%
All Other	$1.17	$0.49	($0.68)	1.5%
Dispatchable Transactions	$1.42	$0.22	($1.20)	2.7%
Total	$76.81	$31.86	($44.95)	100.0%

128 Id.

Shortage

PJM's real-time energy market experienced five minute shortage pricing for one or more reserve products for 41 unique five minute intervals across 6 days in the first nine months of 2023. PJM implemented fast start pricing on September 1, 2021. In the first nine months of 2023, there were 41 unique five minute intervals with real-time shortage pricing in the pricing run for one or more reserve products, and 41 unique intervals with real-time shortage pricing in the dispatch run for one or more reserve products. Table 3-80 shows a summary of the number of days of the emergency alerts, warnings and actions that were declared in PJM in the first nine months of 2022 and the first nine months of 2023. In the first nine months of 2023, there were zero days with emergency actions that triggered Performance Assessment Intervals (PAI).

Table 3-80 Summary of emergency events declared: January through September, 2022 and 2023

	Number of days events declared	
Event Type	2022 (Jan-Sep)	2023 (Jan-Sep)
Cold Weather Alert	7	3
Hot Weather Alert	31	21
Maximum Emergency Generation Alert	1	3
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	3	0
Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time)	3	0
Maximum Emergency Action	0	0
Emergency Energy Bids Requested	0	0
Voltage Reduction Action	0	0
Shortage Pricing	16	41
Energy export recalls from PJM capacity resources	0	0

Figure 3-50 shows the number of days that weather and capacity emergency alerts were issued in PJM in the first nine months of 2014 through 2023.

Figure 3-50 Declared emergency alerts: January through September, 2014 through 2023

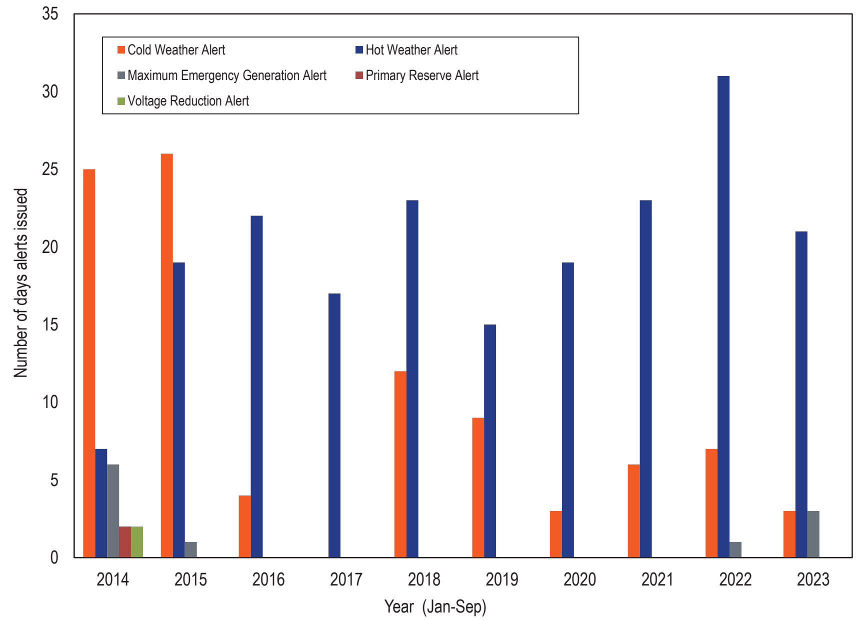
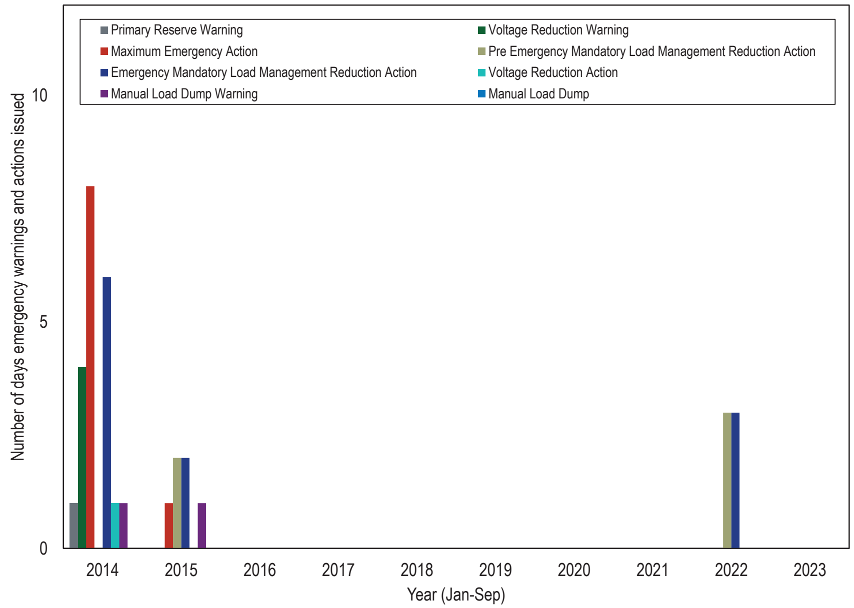


Figure 3-51 shows the number of days that emergency warnings and actions were declared in PJM in the first nine months of the year from 2014 through 2023.

Figure 3-51 Declared emergency warnings and actions: January through September, 2014 through 2023



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 3-81 provides a description of PJM declared emergency procedures.[129 130 131 132]

Table 3-81 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.

129 See PJM. "Manual 13: Emergency Operations," Rev. 88 (May 18, 2023), Section 3.3 Cold Weather Advisory / Alert.
130 See PJM. "Manual 13: Emergency Operations," Rev. 88 (May 18, 2023), Section 3.4 Hot Weather Alert.
131 See PJM. "Manual 13: Emergency Operations," Rev. 88 (May 18, 2023), Section 2.3.1 Advanced Notice Emergency Procedures: Alerts.
132 See PJM. "Manual 13: Emergency Operations," Rev. 88 (May 18, 2023), Section 2.3.2 Real-Time Emergency Procedures (Warnings and Actions).

Table 3-82 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in the first nine months of 2023.

Table 3-82 Declared emergency alerts, warnings and actions: January through September, 2023

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
31-Jan-23	COMED													
3-Feb-23	PJM RTO													
2-Jun-23		PJM RTO												
5-Jul-23		PJM RTO												
6-Jul-23		Mid-Atlantic												
12-Jul-23		Mid-Atlantic, Southern												
13-Jul-23		Mid-Atlantic, Southern												
17-Jul-23		Mid-Atlantic, Southern												
18-Jul-23		Mid-Atlantic, Southern												
26-Jul-23		PJM RTO												
27-Jul-23		PJM RTO												
28-Jul-23		PJM RTO												
29-Jul-23		Mid-Atlantic, Southern												
21-Aug-23		PJM RTO												
22-Aug-23		PJM RTO												
23-Aug-23		Western												
24-Aug-23		Western												
25-Aug-23		Southern, Western												
4-Sep-23		PJM RTO												
5-Sep-23		PJM RTO												
6-Sep-23		PJM RTO												
7-Sep-23		Mid-Atlantic, Southern												
8-Sep-23		Mid-Atlantic, Southern												

Power Balance Constraint Violation

The purpose of the real-time energy market is to dispatch sufficient supply to meet demand. In the RT SCED optimization, the power balance constraint enforces the requirement that total dispatched generation (supply) equals the sum total of forecasted load, losses and net interchange (demand). The power balance constraint is violated when supply is less than demand. In some cases, the power balance constraint is violated while the reserve requirements are satisfied.

The current process for meeting energy and reserve requirements in real time, and pricing the system conditions when RT SCED forecasts that energy supply is less than the demand for energy and reserves, is opaque and not defined in the PJM governing documents. It is unclear whether and how PJM converts reserves to energy before violating the power balance constraint. It is unclear whether and when PJM uses its authority under the tariff to curtail exports from PJM capacity resources to meet the power balance constraint. It is unclear whether PJM would maintain a minimum level of synchronized reserves even if that would result in a controlled load shed. The current RT SCED does not have a mechanism to convert inflexible reserves procured by the ASO to energy to satisfy the power balance constraint.[133] SCED solutions from October 1, 2019, February 16, 2020, and April 21, 2020, indicate that the currently defined logic meets transmission constraint limits and reserve requirements but violates the power balance constraint, and does not reflect this constraint violation in prices. This logic, if correctly described and if there was an actual power balance constraint violation, is not consistent with basic economics. The overall solution is complex and must be integrated with the approach to shortage pricing.

During Winter Storm Elliott, on December 23, 2022, and December 24, 2022, PJM created what they termed "virtual" generation in real time to satisfy the power balance constraint. PJM did not convert any inflexible reserves to energy. In summary, the power balance constraint was violated solely as a result of load bias added by PJM and that violation was corrected by PJM adding generation that does not exist to the supply (virtual generation or supply bias). To the extent that there was an actual violation of the power balance constraint, it was appropriate that PJM did not take actions to address the nonexistent violation. But, the process needs to be clarified to help ensure that an artificial power balance constraint violation does not affect prices.

The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. Table 3-83 shows the number of five minute intervals for which the RT SCED solutions did not balance demand and supply. PJM reran the RT SCED with artificially increased supply to satisfy the power balance constraint. In the first nine months of 2023, there were 16 five minute intervals using an RT SCED solution with a violated power balance constraint. PJM ignored (relaxed) the power balance constraints in the first nine months of 2023 and, as a result, the power balance violation was not included in prices. It is unclear how PJM calculates prices when the power balance constraint is violated.

133 Inflexible reserves are those reserves that clear in the hour ahead Ancillary Service Optimizer (ASO) but cannot be dispatched in the real time dispatch tool, RT SCED.

Table 3-83 Number of five minute intervals using RT SCED solutions with violated power balance constraint by year

Year	Number of five minute intervals	Average Energy Component of LMP in SCED ($/MWh)	Average Energy Component of LMP in Pricing Run ($/MWh)
2013	-	$0.00	$0.00
2014	655	$36.29	$36.29
2015	71	($0.76)	($0.76)
2016	42	$93.06	$93.06
2017	31	$279.86	$279.86
2018	16	$268.21	$268.21
2019	36	$845.48	$845.48
2020	5	$351.56	$351.56
2021	10	$976.06	$976.06
2022	121	$2,347.33	$2,066.21
2023 (Jan - Sep)	16	$407.06	$406.62

Figure 3-52 and Figure 3-53 show forecasted load including operator load bias and total cleared generation, demand response and net scheduled interchange in the SCED solutions approved for each five minute interval on December 23, 2022 and December 24, 2022 during Winter Storm Elliott. There is a power balance violation when the forecasted load plus losses plus operator bias (blue curve) exceeds the generation plus demand response plus net interchange (orange curve).

Figure 3-52 Power balance constraint violations: December 23, 2022

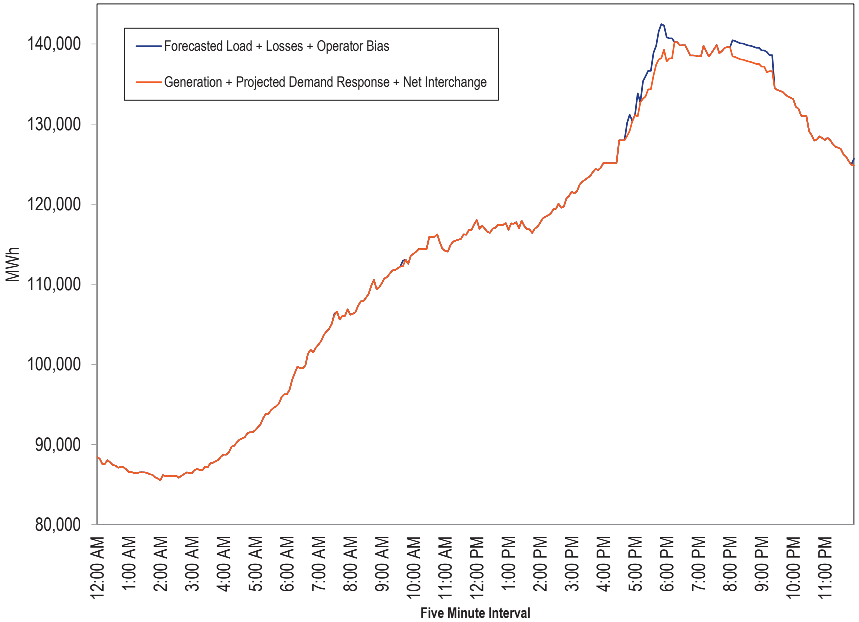
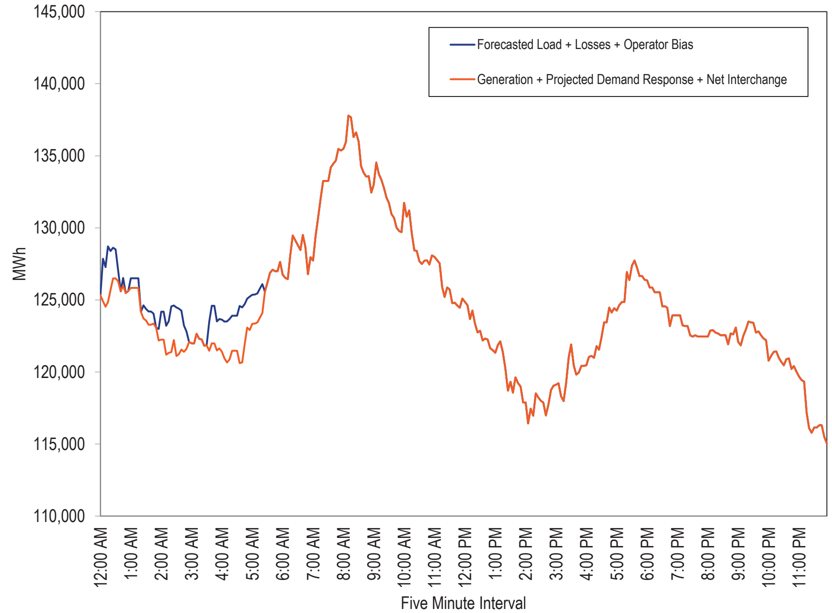


Figure 3-53 Power balance constraint violations: December 24, 2022



Shortage and Shortage Pricing

In electricity markets, shortage means that demand, including reserve requirements, is nearing the limits of the currently available capacity of the system. Shortage pricing is a mechanism for signaling scarcity conditions through higher energy prices. Under the PJM rules that were in place through September 30, 2012, shortage pricing resulted from the exercise of aggregate market power 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 shortage pricing and made it difficult to distinguish between market power and shortage pricing. Shortage pricing is an administrative 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 2023, there were 41 five minute intervals with real-time shortage pricing for one or more reserve products that occurred on six days in PJM.

In 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.[134] Prior to May 11, 2017, if the dispatch tools (Intermediate-Term SCED and Real-Time SCED) reflected a shortage of reserves (primary or synchronized) for a time period shorter than a defined threshold (30 minutes), it was considered a transient shortage, a shortage event was not declared, and shortage pricing was not implemented. 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. In January 2019, PJM updated its business rules in Manual 11 to describe PJM's implementation of the five minute shortage pricing process. PJM Manual 11 states that shortage pricing is triggered when an approved RT SCED case that was used in the Locational Pricing Calculator (LPC) indicates a shortage of reserves. The implementation is not as algorithmic as intended by Order No. 825, because RT SCED can indicate a shortage that PJM does not use in pricing and because the bias added to SCED may artificially create or suppress shortages. On June 22, 2020, PJM reduced the frequency of automatic RT SCED executions to match the frequency of pricing at five minutes, which reduced the frequency of unpriced shortage solutions.

Prior to September 1, 2021, the reserves calculated in the LPC solution, and the reserves calculated in the reference RT SCED case used by the LPC solution were the same. With the implementation of fast start pricing on September 1, 2021, shortage pricing is now triggered by the pricing run in LPC.[135] This can lead to differences between the dispatched reserves in RT SCED and the reserves calculated in the pricing run in LPC. In the pricing run in LPC, shortage pricing could be triggered even when there is no actual shortage in dispatched reserves as determined by the reference RT SCED solution. This occurred during zero intervals in the first nine months of 2023.

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 prices should reflect that condition, even if the data do not show a shortage of reserves.[136]

Operating Reserve Demand Curves

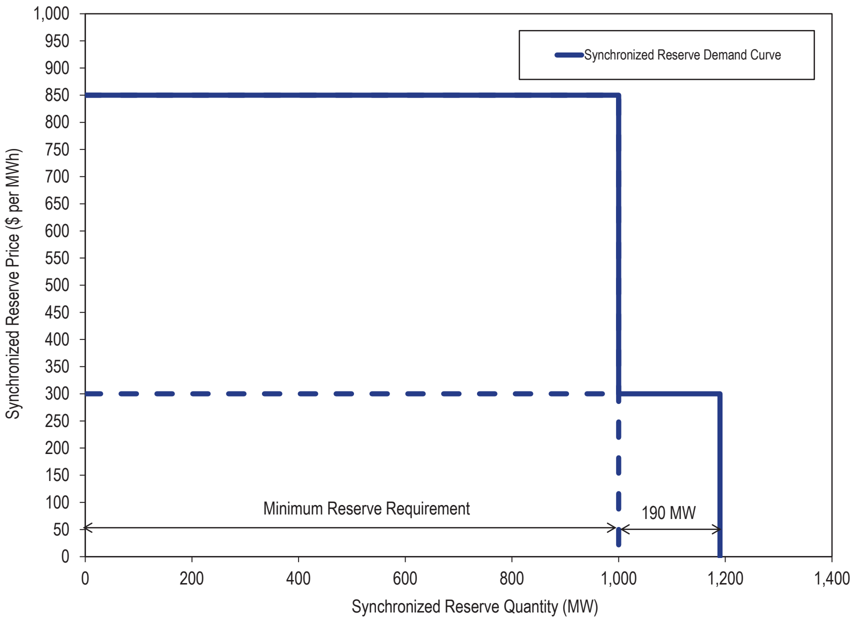
Shortage pricing in the PJM Energy Market can occur in either the day-ahead or the real-time market for any of five reserves requirements: RTO Synchronized Reserves, Subzone Synchronized Reserves, RTO Primary Reserves, Subzone Primary Reserves, and 30 Minute Reserves. Each requirement is modelled in the market clearing engines as a demand curve priced at $850 per MWh up to the minimum reserve requirement (MRR) and at $300 per MWh for an additional 190 MW of reserves. When a reserve constraint is not satisfied, the value on the demand curve for the cleared amount of reserves is added to the market clearing cost-minimization objective function, which makes the demand curve value the administratively determined marginal cost of the reserve shortage. Because an additional MW of energy on the margin would require another MW of reserves shortage, the administrative marginal cost of reserves is added to LMP.

Shortage 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 example demand curve shown in Figure 3-54 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.

134 *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 155 FERC ¶ 61,276 at P 162 (2016).
135 *See* PJM Operating Agreement, Schedule 1, Section 2.5.1(a).
136 *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).

Figure 3-54 Example real-time extended synchronized reserve demand curve showing the permanent second step



Historically, the minimum reserve requirement has equaled the size of the largest single source of supply on the PJM system, the most severe single contingency. Beginning May 12, 2023, PJM unilaterally increased the minimum reserve requirement based on what appeared to be low response rates from reserves but not based on any evidence about reliability issues. This increase resulted in more shortages in the first nine months of 2023. The changes to the reserve requirements are discussed in more detail in Section 10: Ancillary Service Markets of this Report.

Nesting

The reserve requirements are nested such that the faster responding reserves count toward the requirements for slower reserves and such that the reserves in the subzone count toward the total RTO requirement. For example, synchronized reserves count toward the primary reserve requirement, and Mid-Atlantic Dominion reserves count toward the PJM RTO reserve requirement. This nesting means that the effect of reserve constraints on prices can be additive.

The effect of the reserve constraints on pricing depends on the constraint shadow price. In general, the shadow price of a constraint is the change in the total production cost (the objective function of the market dispatch software) if that constraint limit were increased on the margin. A reserve constraint violation (a shortage) means that the constraint cannot be satisfied at a marginal cost less than the value on the ORDC. For the RTO synchronized reserve constraint, the shadow price during a shortage is defined to equal the ORDC value. For the MAD synchronized reserve constraint, when reserves from both the RTO and MAD can be used, the shadow price equals the sum of the ORDC value for each constraint when both are violated. The same occurs for the primary and secondary reserve constraints. The total shadow price of reserve violations can reach five times the highest ORDC value of $850 per MWh, which is $4,250 per MWh. This value exceeds the PJM $1,700 per MWh price caps on reserve prices and the $3,700 per MWh price cap applied to the energy component of LMP, also called the system marginal price.

Energy and Reserve Price Caps

Table 3-84 shows six example scenarios, under the current ORDCs, with combinations of energy offers, reserve shortage penalty factors and transmission constraint penalty factors that can add up to produce high LMPs at sample pnodes in the MAD Reserve Subzone and outside the MAD Reserve Subzone.

Scenario A shows a simple shortage in the RTO Reserve Zone. In scenario B, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones that results in a $1,700 per MWh reserve shortage penalty in the RTO zone LMP and a $3,400 per MWh reserve shortage penalty in the MAD Zone LMP. The marginal resource for energy is in the RTO Zone, and the RTO to MAD reserve transfer constraint is not binding, so the higher MAD reserve penalty does not affect the rest of RTO LMP. In scenario

C, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones and a violated transmission constraint that affects the marginal congestion costs in the system marginal price.

In scenario C, the sum of the marginal unit cost, reserve and transmission constraint penalty factors equals $5,450 per MWh, which exceeds $3,700 per MWh, so SMP capping is triggered whether the marginal unit for energy can provide reserves for the MAD Zone or only the RTO Zone.

In scenario D, with a $1,000 per MWh offer price for the marginal unit for energy, violation of four reserve penalty factors only triggers SMP capping if the marginal unit for energy can serve the MAD reserve requirement. Scenario E and F show that LMPs can exceed $3,700 per MWh if there is a violated transmission constraint that is not exacerbated by an increase in load at the load weighted reference pricing node, which determines the SMP.[137]

In Scenario F, the energy component of LMP is at its highest level, $2,000 per MWh and there is a reserve shortage for primary and synchronized reserves in both MAD and RTO Reserve Zones and a shortage of 30 minute reserves, resulting in a capped $1,700 per MWh scarcity adder, and a violated transmission constraint with $2,000 per MWh penalty factor that results in a $5,700 per MWh LMP. The LMPs in Scenario F are not the highest possible LMPs in the PJM energy market under the current rules. If there are multiple violated transmission constraints, the congestion costs contributing to the LMP at a pnode can exceed $2,000 per MWh resulting in LMPs higher than $5,700 per MWh. The extent to which each violated transmission penalty factor affects the LMP at a pnode is directly proportional to the pnode's distribution factor (dfax) with respect to that constraint. In addition, the LMP at a pnode includes a loss component calculated as the product of marginal loss factor and uncapped system marginal price.

Table 3-84 Real-time additive penalty factors under reserve shortage and transmission constraint violations: Status Quo

		Synchronized Reserve Penalty Factor		Primary Reserve Penalty Factor		30 Minute Reserve Penalty Factor	Transmission Constraint Penalty Factor	System Marginal Price		Transmission Constraint Penalty Factor	Total LMP	
Scenario	Marginal Unit Offer Price	RTO	MAD	RTO	MAD	RTO	in SMP	RTO Marginal	MAD Marginal	in CLMP	RTO Marginal	MAD Marginal
A	$50	$850	$0	$0	$0	$0	$0	$900	$900	$0	$900	$900
B	$50	$850	$850	$850	$850	$0	$0	$1,750	$3,450	$0	$1,750	$3,450
C	$50	$850	$850	$850	$850	$0	$2,000	$3,700	$3,700	$0	$3,700	$3,700
D	$1,000	$850	$850	$850	$850	$0	$0	$2,700	$3,700	$0	$2,700	$3,700
E	$1,000	$850	$850	$850	$850	$850	$2,000	$3,700	$3,700	$2,000	$5,700	$5,700
F	$2,000	$850	$850	$850	$850	$850	$2,000	$3,700	$3,700	$2,000	$5,700	$5,700

Circuit Breaker

Due to the high prices that are possible in a shortage situation, PJM stakeholders initiated a discussion in 2021 about a circuit breaker mechanism that would reduce prices in some circumstances. There are possible scenarios under the PJM market design in which excessively high administrative pricing in the energy market under the current tariff provisions would impose inefficient wealth transfers. Inefficient wealth transfers from load to generation, among generators, or from physical to financial market participants occur when administrative pricing creates arbitrarily high price signals. A circuit breaker should be simple, with a nondiscretionary trigger, like high LMPs, and only administrative components of price should be capped. Capping overall LMP, as PJM and some stakeholders proposed, risks interfering with efficient price setting based on high short run marginal costs, e.g. fuel costs but not arbitrarily high operation and maintenance

137 The impact of the transmission constraint penalty factor at a pnode depends on its distribution factor (dfax) with respect to the constraint. The scenarios here assume a single violated transmission constraint with dfax of 1.0. If there are multiple violated transmission constraints, the total impact at a pnode is the sum of the product of transmission constraint penalty factors and distribution factors.

expense that are not actually marginal costs. A better solution than a circuit breaker would be to reduce the default shortage pricing levels, as defined by the sum of ORDC penalty factors, to avoid inefficient wealth transfers.

Some of the circuit breaker proposals made in the stakeholder process would have applied during Winter Storm Elliott. The PJM load-weighted average LMP was greater than $1,000 per MWh for a 24 hour period. Of the hours when LMP was greater than $1,000 per MWh, only one hour on December 24 reached that level as a result of high fuel prices. In all other hours, administrative components of LMP set prices above $1,000 per MWh. The MMU proposes that, if there is a circuit breaker cap, only the administrative components of LMP be capped. Administrative components include ORDC penalty factors, transmission constraint penalty factors, and the maximum demand response strike price. Capping administrative components would prevent arbitrarily high prices while ensuring that the actual costs of meeting demand are included in prices. With no circuit breaker proposals prevailing in the stakeholder process, the PJM Board announced on August 3, 2023, that PJM would not pursue a market rule change to implement a circuit breaker.[138]

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 directly reflected in the ORDC when operational issues arise, allowing the market to efficiently account for the reliability commitment in the energy and reserves markets. During Elliott, PJM committed additional generation to provide reserves but did not increase the reserve requirements correspondingly.

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 to, for example, commit more reserves when specific needs arise in a specific location.

Shortage Pricing During Synchronized Reserve Events

Synchronized reserves are deployed when PJM declares a synchronized reserve event, also known as a spinning event. Currently, spinning events are triggered by an all call message to the system requesting all online generation units to increase their energy output. This deployment mechanism is used regardless of the actual MW needed to recover the Area Control Error (ACE) to zero or to the pre-event levels. While the all call message signals resources to increase their output, the approved SCED cases are solved with the reserve requirement intact, which dispatches the system to meet the load and reserve requirements ten to fourteen minutes into the future. This results in a discrepancy between the operational need during a spinning event, and the RT SCED solutions. PJM's instruction to generators is to ignore the dispatch signals sent by RT SCED, and instead continue to ramp their units up until the spin event ends.

Under the reserve market enhancements that began October 1, 2022, all synchronized reserves are treated as a uniform product and paid the market clearing price for synchronized reserves. All synchronized reserves are also assessed a penalty for nonperformance during the synchronized reserve events. Deployment of reserves during synchronized reserve events will be most efficient if the resources that are deployed and are subject to performance evaluation for their response are the resources that are committed as synchronized reserves. However, under PJM's proposed Intelligent Reserve Deployment (IRD) approach, PJM would rely on units that do not have a reserve commitment, while unnecessarily holding back committed and compensated reserve units during a spin event.[139] This is because the IRD approach is just a SCED solution based on: load increased by a predetermined amount; inflexible synchronized reserves converted to energy production; and maintaining the reserve requirement. The result is that inflexible synchronized reserves are converted to energy production, while flexible resources are held as reserves to meet the reserve requirement instead of responding to the spin event. Since

138 "PJM Board Letter Regarding Implementation of an Energy Market Circuit Breaker," PJM Notification to Stakeholders (August 3, 2023), <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20230803-pjm-board-letter-re-implementation-of-energy-market-circuit-breaker.ashx>.

139 PJM. "Intelligent Reserve Deployment PJM Package," presented at the Synchronous Reserve Deployment Task Force, (July 1, 2021) at 3, *which can be accessed at* <https://www.pjm.com/-/media/committees-groups/task-forces/srdtf/2021/20210701/20210701-item-03-pjms-proposed-package-intelligent-reserve-deployment.ashx>.

PJM proposes penalties for lack of response during spin events for cleared and dispatched reserves, this results in inflexible synchronized reserve resources potentially being subject to penalties disproportionately, while flexible synchronized reserves may or may not be dispatched, and consequently may not be not subject to penalties. The IRD mechanism also creates a reliability risk since it relies on resources not committed as reserves to increase their output to recover ACE during a spin event, and these resources are not subject to a penalty for nonperformance. For these reasons, FERC rejected PJM's IRD proposal on August 15, 2022.[140]

While PJM recovers from a disturbance during a spinning event, PJM should also adjust the operating reserve demand curve (ORDC) for synchronized reserves to ensure that RT SCED does not have a competing objective of immediately replacing reserves that have been paid for, and are being used for their intended purpose. Without such an adjustment, RT SCED will have to depend on resources that are not deemed to be eligible for clearing as synchronized reserves to aid the recovery of ACE. Without such an adjustment, the prices will be artificially inflated, potentially triggering shortage pricing, during the times when reserves are used for their intended purpose. The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirement for synchronized and primary reserves by the amount of the reserves deployed.

Reserve Shortages in 2023

Reserve Shortage in Real-Time SCED

The MMU analyzed the RT SCED solutions to determine how many of the five minute target time RT SCED solutions indicated a shortage of any of the reserve products (synchronized reserve and primary reserve at RTO Reserve Zone and MAD Reserve Subzone), when multiple solutions indicated shortage of reserves, and how many of these resulted in shortage prices in LPC. For reliability reasons, and to maintain reserves to comply with NERC standards, reserves are considered short if the quantity (MW) of reserves dispatched by RT SCED for a five minute interval is less than the minimum reserve requirement (MRR). To trigger shortage pricing, reserves are considered short if the quantity (MW) of reserves dispatched by RT SCED for a five minute interval is less than the extended reserve requirement.

Until June 2, 2021, PJM generally solved one RT SCED case with three solutions per case, for each five minute target time.[141] [142] On June 3, 2021, PJM updated RT SCED to solve two additional scenarios, or a total of five solutions per case. In 2021, the frequency with which RT SCED solutions were approved increased to one solution per five minute interval. This approval frequency increased the proportion of approved SCED solutions that are reflected in LMPs. However, the process of selecting the SCED solution to approve, among the solutions available to PJM operators, is subjective and is not based on clearly defined criteria. The criteria are especially important when only some of the SCED solutions reflect shortage pricing, and the rest of the solutions do not.

The MMU analyzed the target times for which one or more RT SCED case solutions indicated a shortage of one or more reserve products. Table 3-85 shows, for each month of 2022 and the first nine months of 2023, the total number of target times, the number of target times for which at least one RT SCED solution showed a shortage of reserves, the number of target times for which more than one RT SCED solution showed a shortage of reserves, and the number of five minute pricing intervals for which the LPC solution showed a shortage of reserves. Each execution of RT SCED produces five solutions, using five different levels of load bias. Table 3-85 shows that, in the first nine months of 2023, 2,475 target times, or 3.1 percent of all five minute target times, had at least one RT SCED solution showing a shortage of reserves, and 845 target times, or 1.1 percent of all five minute target times, had more than one RT SCED solution showing a shortage of reserves. In 2022, there were 9,026 target times, or 8.6 percent of all five minute target times, that had at least one RT SCED solution showing a shortage of reserves, and 2,766 target times, or 2.6 percent of all five minute target times, that had more than one RT SCED solution showing a shortage of reserves.

140 *See* 180 FERC ¶ 61,089 (August 15, 2022).

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

142 PJM updated the RT SCED execution frequency to solve one case for each five minute target time beginning June 22, 2020. PJM dispatchers may solve additional cases at their discretion.

Table 3-85 Real-time monthly five minute SCED target times and pricing intervals with shortage: January 2022 through September 2023

Year	Month	Number of Five Minute Intervals	Number of Target Times With At Least One SCED Solution Short of Reserves	Percent Target Times With At Least One SCED Solution Short of Reserves	Number of Target Times With Multiple SCED Solutions Short of Reserves	Percent Target Times With Multiple SCED Solutions Short of Reserves	Number of Five Minute Intervals With Shortage Prices in LPC	Percent RT SCED Target Times With Reserve Shortage With Shortage Prices in LPC
2022	Jan	8,928	904	10.1%	276	3.1%	14	1.5%
2022	Feb	8,064	544	6.7%	153	1.9%	0	0.0%
2022	Mar	8,916	1,306	14.6%	381	4.3%	5	0.4%
2022	Apr	8,640	1,114	12.9%	343	4.0%	3	0.3%
2022	May	8,928	1,008	11.3%	265	3.0%	1	0.1%
2022	Jun	8,640	714	8.3%	170	2.0%	38	5.3%
2022	Jul	8,928	785	8.8%	223	2.5%	1	0.1%
2022	Aug	8,928	927	10.4%	263	2.9%	0	0.0%
2022	Sep	8,640	731	8.5%	187	2.2%	0	0.0%
2022	Oct	8,928	399	4.5%	151	1.7%	1	0.3%
2022	Nov	8,652	138	1.6%	46	0.5%	0	0.0%
2022	Dec	8,928	456	5.1%	308	3.4%	207	45.4%
2022	Total	105,120	9,026	8.6%	2,766	2.6%	270	3.0%
2023	Jan	8,928	187	2.1%	63	0.7%	3	1.6%
2023	Feb	8,064	89	1.1%	16	0.2%	0	0.0%
2023	Mar	8,916	75	0.8%	22	0.2%	0	0.0%
2023	Apr	8,640	444	5.1%	146	1.7%	0	0.0%
2023	May	8,928	948	10.6%	396	4.4%	35	3.7%
2023	Jun	8,640	268	3.1%	84	1.0%	0	0.0%
2023	Jul	8,928	219	2.5%	60	0.7%	1	0.5%
2023	Aug	8,928	115	1.3%	24	0.3%	0	0.0%
2023	Sep	8,640	130	1.5%	34	0.4%	2	1.5%
2023	Total	78,612	2,475	3.1%	845	1.1%	41	1.7%

In the first nine months of 2023, there were 845 unique five minute target times for which multiple RT SCED solutions showed a shortage of reserves for one or more reserve services, while there were 41 unique five minute intervals with real-time shortage pricing for one or more reserve products. In 2022, there were 2,766 unique five minute target times for which multiple RT SCED solutions showed a shortage of reserves for one or more reserve services, while there were 270 five minute intervals with shortage pricing for one or more reserve products. Clear criteria for approval of shortage cases are needed.

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 or implement shortage pricing when there are no 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 pattern of shortage case approvals in Table 3-85 indicates that PJM operators consider factors other than RT SCED and LPC results when deciding whether to approve shortage cases. After a 5.3 percent approval rate in June 2022, the approval rate dropped to close to zero percent until December 2022 when it rose to 45.4 percent. The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases that are used to send dispatch signals to resources, and for pricing, to minimize discretion. A rule based approach is essential for defining how LMPs are determined so that all market participants can be confident that energy market pricing is efficient.

Shortage Pricing Intervals in LPC

Beginning October 1, 2022, shortage pricing can occur in both the PJM Day-Ahead and Real-Time Energy Markets for Synchronized Reserves, Primary Reserves, and Thirty Minute Reserves. In the first nine months of 2023, there was no shortage pricing in the day-ahead energy market.

There were 41 unique real-time five minute intervals with shortage pricing for one or more reserve products in the first nine months of 2023, compared to 62 intervals in the first nine months of 2022. As of the first nine months of 2023, there has never been shortage pricing in the day-ahead market. PJM implemented fast start pricing on September 1, 2021. Fast start pricing can result in differences in reserve shortages between the dispatch run and the pricing run, although there were no differences in the first nine months of 2023. In the first nine months of 2023, there were 41 five minute intervals with shortage pricing in the pricing run for one or more reserve products, and 41 intervals with shortage in the dispatch run for one or more reserve products.

Table 3-86 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 17 intervals with shortage pricing in the pricing run due to a synchronized reserve shortage in the first nine months of 2023. Table 3-86 shows that the 17 intervals had a synchronized reserve shortage for the RTO Reserve Zone in the dispatch run.

Table 3-87 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 one interval with shortage pricing in the pricing run due to synchronized reserve shortage in the first nine months of 2023. Table 3-87 shows that the one interval had a synchronized reserve shortage for the MAD Subzone in both the dispatch run and pricing run.

Table 3-88 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 38 intervals with shortage pricing in the pricing run due to primary reserve shortage in the first nine months of 2023. Table 3-88 shows that all 38 intervals were short of primary reserves in the pricing run and the dispatch run. Of these intervals, 11 occurred on May 12, 2023, and 17 of these intervals occurred on May 15, 2023. On those dates, PJM unilaterally extended the second step of the ORDC by 1,588 MW in an attempt to compensate for poor reserve performance by scheduling more reserve, even though there was no change to the largest single contingency which would have required such as increase.[143] As seen in Table 3-88 during these intervals of triggered shortage pricing, PJM actually cleared far more primary reserve than it would have when using its usual ORDC. In the first four months of 2023, prior to this change, the average primary reserve requirement was 2,488.7 MW, while PJM cleared over 4,000 MW of primary reserve during many of these intervals that were artificially defined to be short as a result of PJM's unilateral extension of the ORDC.

Table 3-89 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 three intervals with shortage pricing in the pricing run due to primary reserve shortage in the first nine months of 2023. Table 3-89 shows that all three of the intervals were short of primary reserves in both the dispatch run and the pricing run, and that two of the intervals had different capped prices in the dispatch and pricing runs.

PJM enforces an RTO wide reserve requirement and a reserve requirement for the MAD region. The MAD Reserve Subzone is inside 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

143 *See* "PJM's Proposed Changes to Reserve Requirements," MMU Presentation to the Markets and Reliability Committee (May 31, 2023) and Section 10: Ancillary Service Markets of this Report for further discussion.

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.[144] The synchronized reserve clearing price of the MAD Reserve Subzone 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.

The process of calculating reserve constraint shadow prices and implementing reserve price caps in PJM is not transparent. The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM manuals, including definitions of all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices.

The PJM tariff caps the MCP for primary reserves at one and a half times the nonsynchronized reserve penalty factor for each zone or subzone, and caps the MCP for synchronized reserves at the sum of the penalty factor for synchronized reserve and the penalty factor for nonsynchronized reserve, but the PJM tariff does not explicitly specify a cap on the system marginal price.[145] The system marginal price cap should be included in the PJM tariff and Operating Agreement.

Table 3-86 Real-time RTO synchronized reserve shortage intervals: January through September, 2023

	Pricing Run					Dispatch Run				
Interval (EPT)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	Uncapped RTO Synchronized Reserve Clearing Price ($/MWh)	Capped RTO Synchronized Reserve Clearing Price ($/MWh)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	Uncapped RTO Synchronized Reserve Clearing Price ($/MWh)	Capped RTO Synchronized Reserve Clearing Price ($/MWh)
10-Jan-23 07:15	1,861.0	1,608.0	253.0	$1,700.00	$1,700.00	1,861.0	1,608.0	253.0	$1,700.00	$1,700.00
12-May-23 01:55	3,343.0	3,277.5	65.5	$600.00	$600.00	3,343.0	3,277.4	65.6	$600.00	$600.00
12-May-23 02:00	3,343.0	3,277.5	65.5	$600.00	$600.00	3,343.0	3,277.4	65.6	$600.00	$600.00
12-May-23 02:05	3,343.0	3,270.9	72.1	$600.00	$600.00	3,343.0	3,270.9	72.1	$600.00	$600.00
12-May-23 02:15	3,345.0	3,334.1	10.9	$600.00	$600.00	3,345.0	3,334.1	10.9	$600.00	$600.00
12-May-23 02:20	3,348.0	3,333.9	14.1	$600.00	$600.00	3,348.0	3,333.9	14.1	$600.00	$600.00
15-May-23 00:20	3,552.0	3,489.3	62.7	$300.00	$300.00	3,552.0	3,489.3	62.7	$300.00	$300.00
15-May-23 00:25	3,552.0	3,308.3	243.7	$300.00	$300.00	3,552.0	3,308.3	243.7	$300.00	$300.00
15-May-23 00:30	3,552.0	3,250.3	301.7	$300.00	$300.00	3,552.0	3,250.3	301.7	$300.00	$300.00
15-May-23 00:35	3,552.0	2,978.2	573.8	$600.00	$600.00	3,552.0	2,978.2	573.8	$600.00	$600.00
15-May-23 00:40	3,552.0	3,019.3	532.7	$600.00	$600.00	3,552.0	3,019.3	532.7	$600.00	$600.00
15-May-23 00:45	3,552.0	3,019.3	532.7	$600.00	$600.00	3,552.0	3,019.3	532.7	$600.00	$600.00
15-May-23 00:50	3,552.0	3,073.8	478.2	$600.00	$600.00	3,552.0	3,073.8	478.2	$600.00	$600.00
15-May-23 01:20	3,552.0	3,531.4	20.6	$600.00	$600.00	3,552.0	3,531.4	20.6	$600.00	$600.00
15-May-23 01:25	3,552.0	3,459.1	92.9	$600.00	$600.00	3,552.0	3,459.1	92.9	$600.00	$600.00
11-Sep-23 17:45	2,551.2	2,361.2	190.0	$1,362.34	$1,362.34	2,551.2	2,361.2	190.0	$1,362.34	$1,362.34
11-Sep-23 17:50	2,552.1	2,454.0	98.1	$1,150.00	$1,150.00	2,552.1	2,454.0	98.1	$1,150.00	$1,150.00

144 If the reserve requirement cannot be met by the resources located within the reserve zone, the shadow price of the reserve requirement is set by the applicable operating reserve demand curve.
145 OA Schedule 1, Section 3.2.3A(d) and Section 3.2.3A.001(c).

Table 3-87 Real-time MAD synchronized reserve shortage intervals: January through September, 2023

	Pricing Run					Dispatch Run				
Interval (EPT)	MAD Extended Synchronized Reserve Requirement (MW)	Total MAD Synchronized Reserves (MW)	MAD Synchronized Reserve Shortage (MW)	Uncapped MAD Synchronized Reserve Clearing Price ($/MWh)	Capped MAD Synchronized Reserve Clearing Price ($/MWh)	MAD Extended Synchronized Reserve Requirement (MW)	Total MAD Synchronized Reserves (MW)	MAD Synchronized Reserve Shortage (MW)	Uncapped MAD Synchronized Reserve Clearing Price ($/MWh)	Capped MAD Synchronized Reserve Clearing Price ($/MWh)
10-Jan-23 07:15	1,861.0	1,608.0	253.0	$3,400.00	$1,700.00	1,861.0	1,608.0	253.0	$3,400.00	$3,400.00

Table 3-88 Real-time RTO primary reserve shortage intervals: January through September, 2023

	Pricing Run					Dispatch Run				
Interval (EPT)	RTO Extended Primary Reserve Requirement (MW)	Total RTO Primary Reserves (MW)	RTO Primary Reserve Shortage (MW)	Uncapped RTO Primary Reserve Clearing Price ($/MWh)	Capped RTO Primary Reserve Clearing Price ($/MWh)	RTO Extended Primary Reserve Requirement (MW)	Total RTO Primary Reserves (MW)	RTO Primary Reserve Shortage (MW)	Uncapped RTO Primary Reserve Clearing Price ($/MWh)	Capped RTO Primary Reserve Clearing Price ($/MWh)
10-Jan-23 07:10	2,695.0	2,505.0	190.0	$647.40	$647.40	2,695.0	2,505.0	190.0	$647.40	$647.40
10-Jan-23 07:15	2,696.5	1,935.0	761.5	$850.00	$850.00	2,696.5	1,935.0	761.5	$850.00	$850.00
10-Jan-23 07:20	2,695.0	2,375.1	319.9	$850.00	$850.00	2,695.0	2,375.1	319.9	$850.00	$850.00
12-May-23 01:55	4,125.5	3,570.5	555.0	$300.00	$300.00	4,125.5	3,570.4	555.1	$300.00	$300.00
12-May-23 02:00	4,125.5	3,570.5	555.0	$300.00	$300.00	4,125.5	3,570.4	555.1	$300.00	$300.00
12-May-23 02:05	4,125.5	3,563.9	561.6	$300.00	$300.00	4,125.5	3,563.9	561.6	$300.00	$300.00
12-May-23 02:10	4,125.5	3,652.5	473.0	$300.00	$300.00	4,125.5	3,652.5	473.0	$300.00	$300.00
12-May-23 02:15	4,128.5	3,627.1	501.4	$300.00	$300.00	4,128.5	3,627.1	501.4	$300.00	$300.00
12-May-23 02:20	4,133.0	3,626.9	506.1	$300.00	$300.00	4,133.0	3,626.9	506.1	$300.00	$300.00
12-May-23 02:25	4,128.5	3,947.9	180.6	$300.00	$300.00	4,128.5	3,947.9	180.6	$300.00	$300.00
12-May-23 02:30	4,137.5	4,076.8	60.7	$300.00	$300.00	4,137.5	4,076.8	60.7	$300.00	$300.00
12-May-23 02:35	4,130.0	4,036.4	93.6	$300.00	$300.00	4,130.0	4,036.4	93.6	$300.00	$300.00
12-May-23 02:40	4,130.0	4,036.4	93.6	$300.00	$300.00	4,130.0	4,036.4	93.6	$300.00	$300.00
12-May-23 02:45	4,131.5	4,113.8	17.7	$300.00	$300.00	4,131.5	4,113.8	17.7	$300.00	$300.00
15-May-23 00:35	4,439.0	4,171.2	267.8	$300.00	$300.00	4,439.0	4,171.2	267.8	$300.00	$300.00
15-May-23 00:40	4,439.0	4,212.3	226.7	$300.00	$300.00	4,439.0	4,212.3	226.7	$300.00	$300.00
15-May-23 00:45	4,439.0	4,212.3	226.7	$300.00	$300.00	4,439.0	4,212.3	226.7	$300.00	$300.00
15-May-23 00:50	4,439.0	4,266.8	172.2	$300.00	$300.00	4,439.0	4,266.8	172.2	$300.00	$300.00
15-May-23 01:10	4,439.0	4,254.9	184.1	$300.00	$300.00	4,439.0	4,254.9	184.1	$300.00	$300.00
15-May-23 01:15	4,439.0	4,230.4	208.6	$300.00	$300.00	4,439.0	4,230.4	208.6	$300.00	$300.00
15-May-23 01:20	4,439.0	4,139.4	299.6	$300.00	$300.00	4,439.0	4,139.4	299.6	$300.00	$300.00
15-May-23 01:25	4,439.0	4,067.1	371.9	$300.00	$300.00	4,439.0	4,067.1	371.9	$300.00	$300.00
15-May-23 01:30	4,439.0	4,216.7	222.3	$300.00	$300.00	4,439.0	4,217.5	221.5	$300.00	$300.00
15-May-23 01:35	4,439.0	4,318.3	120.7	$300.00	$300.00	4,439.0	4,320.4	118.6	$300.00	$300.00
15-May-23 01:40	4,439.0	4,338.6	100.4	$300.00	$300.00	4,439.0	4,340.3	98.7	$300.00	$300.00
15-May-23 01:45	4,439.0	4,268.3	170.7	$300.00	$300.00	4,439.0	4,270.1	168.9	$300.00	$300.00
15-May-23 01:55	4,439.0	4,411.9	27.1	$300.00	$300.00	4,439.0	4,414.2	24.8	$300.00	$300.00
15-May-23 05:20	4,188.5	4,130.9	57.6	$300.00	$300.00	4,188.5	4,130.9	57.6	$300.00	$300.00
15-May-23 17:45	4,089.5	3,738.5	351.0	$300.00	$300.00	4,089.5	3,738.5	351.0	$300.00	$300.00
15-May-23 17:50	4,091.0	3,819.7	271.3	$300.00	$300.00	4,091.0	3,819.7	271.3	$300.00	$300.00
15-May-23 18:05	4,100.0	4,001.4	98.6	$300.00	$300.00	4,100.0	4,001.4	98.6	$300.00	$300.00
26-May-23 22:05	3,508.3	3,410.9	97.5	$300.00	$300.00	3,508.3	3,410.9	97.4	$300.00	$300.00
26-May-23 22:10	3,501.7	3,384.6	117.0	$300.00	$300.00	3,501.7	3,384.7	117.0	$300.00	$300.00
26-May-23 22:15	3,505.2	3,482.6	22.6	$300.00	$300.00	3,505.2	3,482.7	22.5	$300.00	$300.00
26-May-23 22:20	3,504.6	3,427.6	77.0	$300.00	$300.00	3,504.6	3,427.7	76.9	$300.00	$300.00
21-Jul-23 16:45	3,473.8	3,397.1	76.7	$300.00	$300.00	3,473.8	3,397.1	76.7	$300.00	$300.00
11-Sep-23 17:45	3,731.8	3,176.2	555.6	$850.00	$850.00	3,731.8	3,176.2	555.6	$850.00	$850.00
11-Sep-23 17:50	3,733.2	3,269.0	464.1	$850.00	$850.00	3,733.2	3,269.0	464.1	$850.00	$850.00

Table 3-89 Real-time MAD primary reserve shortage intervals: January through September, 2023

	Pricing Run					Dispatch Run				
Interval (EPT)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	Uncapped MAD Primary Reserve Clearing Price ($/MWh)	Capped MAD Primary Reserve Clearing Price ($/MWh)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	Uncapped MAD Primary Reserve Clearing Price ($/MWh)	Capped MAD Primary Reserve Clearing Price ($/MWh)
10-Jan-23 07:10	2,695.0	2,505.0	190.0	$947.40	$947.40	2,695.0	2,505.0	190.0	$947.40	$947.40
10-Jan-23 07:15	2,696.5	1,935.0	761.5	$1,700.00	$1,275.00	2,696.5	1,935.0	761.5	$1,700.00	$1,700.00
10-Jan-23 07:20	2,695.0	2,375.1	319.9	$1,700.00	$1,275.00	2,695.0	2,375.1	319.9	$1,700.00	$1,700.00

System Marginal Price Cap

Prior to PJM's implementation of the modified reserve markets on October 1, 2022, in the PJM real-time market, the SMP was capped at $3,750 per MWh. This cap was the sum of the Energy Offer Cap ($2,000 per MWh under defined conditions), the Synchronous Reserve Penalty Factor from the first step on the demand curve ($850 per MWh), the Primary Reserve Penalty Factor from the first step on the demand curve ($850 per MWh) and a threshold ($50 per MWh). The Operating Agreement stated that only two, of the four, reserve penalty factors may be applied.

In that prior implementation, if the SMP would otherwise exceed $3,750 per MWh, PJM solved the SCED optimization by progressively relaxing reserve requirement constraints until the SMP fell below the cap. For instance, if the original SMP was above $3,750, PJM would solve the SCED optimization by disabling the subzone (MAD) primary reserve requirement constraint. If the SMP from the relaxed SCED optimization was still above $3,750, PJM would solve the SCED optimization by disabling subzone (MAD) primary and synchronized reserve requirement constraints. If the relaxed SCED optimization was still above $3,750, PJM would solve the SCED optimization by disabling subzone (MAD) primary and synchronized reserve requirement constraints and the RTO primary reserve constraint.

Starting with PJM's implementation of the new Reserve Price Formation rules on October 1, 2022, in the PJM real-time market, the SMP is capped at $3,700 per MWh. Unlike the prior implementation, PJM's new cap does not include a $50 per MWh threshold and is not enforced by progressively relaxing reserve requirement constraints. PJM's new cap is an administrative override of the SMP calculated in the pricing run (LPC). The SMP is not capped in the dispatch run (SCED). The congestion component of the LMP and the loss component of the LMP are not subject to this cap. The LMP at a pricing node could still exceed $3,700 per MWh.

Table 3-90 shows number of five minute intervals in the real time market where the SMP was capped for each year since 2019. In the first nine months of 2023, there was one five minute interval in the real time market where the SMP was capped.

Table 3-90 Number of Five minute intervals with capped SMP: January 2019 through September 2023

Year	Number of Five Minute Intervals with capped SMP
2019	1
2020	1
2021	2
2022	51
2023 (Jan - Sep)	1

The MMU recommends that PJM stop capping the system marginal price in RT SCED and instead limit the sum of violated reserve constraint shadow prices used in LPC to $1,700 per MWh.

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 RT SCED software, such as 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.[146] 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 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. PJM should address these complexities through generator modeling improvements. 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 deselects specific units from providing reserves, and overrides the dispatch signal to certain units to set the dispatch signal equal to actual resource output. These manual interventions are, at best, rough approximations of the capability of generators and result in an inaccurate measurement of reserves.

Competitive Assessment

Market Structure

Market Concentration

The Herfindahl-Hirschman Index (HHI) concentration ratio is the sum of the squares of the market shares of all firms in a market. Hourly PJM energy market HHIs are based on the shares of the real-time energy output of generators adjusted with scheduled imports. Hourly HHIs for the baseload, intermediate and peaking segments of generation supply are based on hourly energy market shares, unadjusted for imports.

The HHI is not a definitive measure of structural market power. It is possible to have pivotal suppliers 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 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. A pivotal supplier test is required to accurately measure the ability of incremental resources to exercise market power.

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

FERC's Merger Policy Statement defines levels of concentration by HHI level. The market is unconcentrated if the market HHI is below 1000, the HHI if there were 10 firms with equal market shares. The market is moderately concentrated if the market HHI is from 1000 to 1800. The market is highly concentrated if the market HHI is greater than 1800, the HHI if there were between five and six firms with equal market shares.[147]

When transmission constraints exist, local markets are created in which ownership 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 2023, 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.

PJM HHI Results

Hourly HHIs indicate that by FERC standards, the PJM energy market in the first nine months of 2023 was unconcentrated on average (Table 3-91).[148] The fact that the average HHI and the maximum hourly HHI are in the unconcentrated 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. Given the low responsiveness of consumers to prices (inelastic demand), it is possible to have high markup even when HHI is low. It is possible to have an exercise of market power even when the HHI level does not indicate a highly concentrated market structure.

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

148 The HHI calculations use actual real time settled generation data for each unit in PJM. Each unit's output is assigned to the owner that is responsible for offering the unit in the energy market.

Table 3-91 Real-time hourly aggregate energy market HHI: January through September, 2022 and 2023

HHI Statistic	Hourly Market HHI (Jan - Sep, 2022)	Hourly Market HHI (Jan-Sep, 2023)
Average	690	682
Minimum	554	528
Maximum	1012	949
Highest market share (One hour)	26%	26%
Average of the highest hourly market share	18%	18%
# Hours	6,551	6,551
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-92 includes HHI values by supply curve segment, including base, intermediate and peaking plants in the first nine months of 2022 and 2023. On average, ownership in the baseload segment was unconcentrated, in the intermediate segment was unconcentrated, and in the peaking segment was highly concentrated.[149] High concentration levels increase the probability that a generation owner will be pivotal in the aggregate market.

Table 3-92 Real-time hourly energy market HHI by generation segment: January through September, 2022 and 2023

	Jan-Sep 2022			Jan-Sep 2023		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	587	721	1032	577	706	971
Intermediate	690	1634	9378	679	1481	7085
Peak	817	6687	10000	812	6240	10000

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

Figure 3-55 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 2023.[150]

Figure 3-55 Real-time ICAP distribution by fuel and segment: January through September, 2023[151]

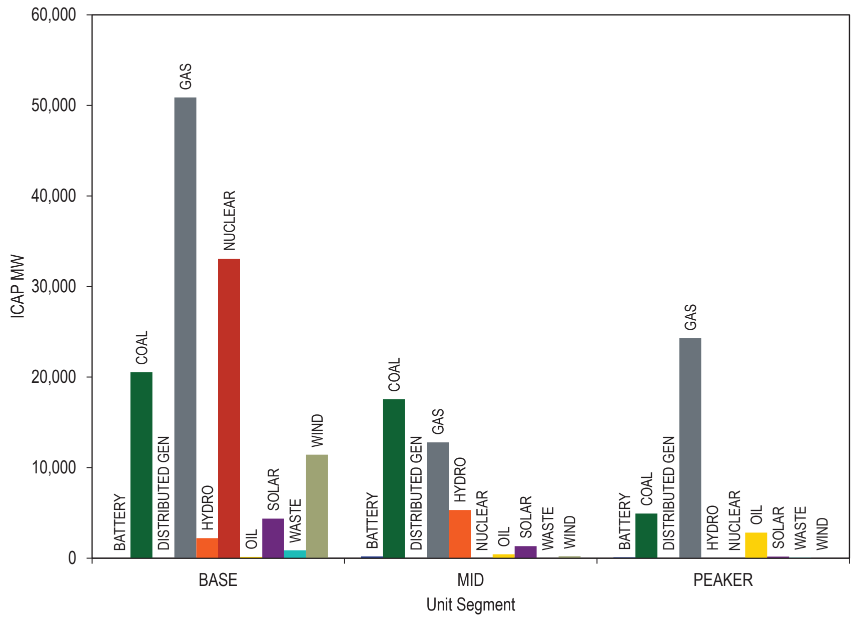
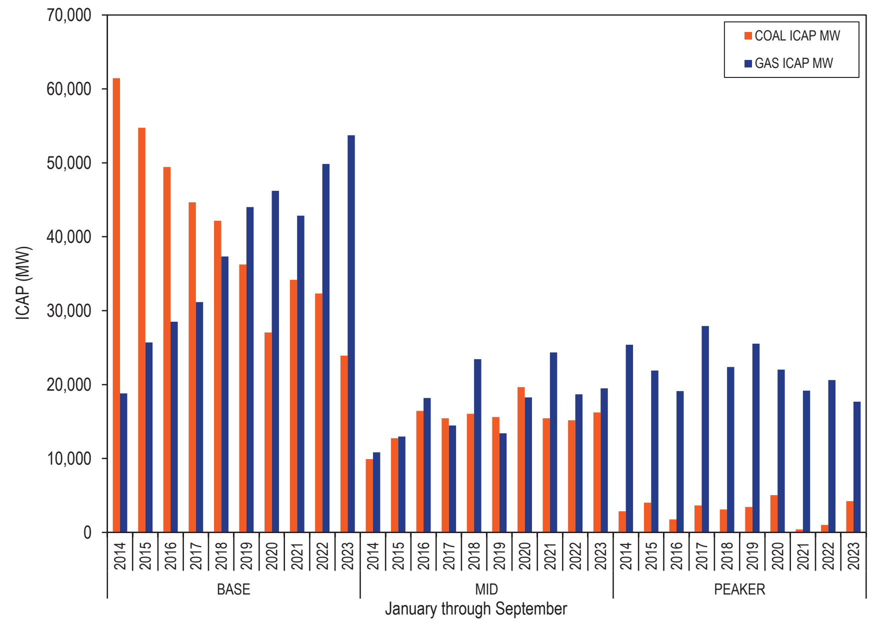


Figure 3-56 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking from 2014 through 2022. Figure 3-56 shows that the total ICAP of coal fired units in PJM classified as baseload generally decreased from 2014 through the first nine months of 2023, while the total ICAP of gas fired units in PJM classified as baseload generally increased. In 2019, the ICAP of gas fired units classified as baseload exceeded the ICAP of coal fired units classified as baseload for the first time.

Figure 3-56 Real-time annual gas and coal unit segment classification: January through September, 2014 through 2023

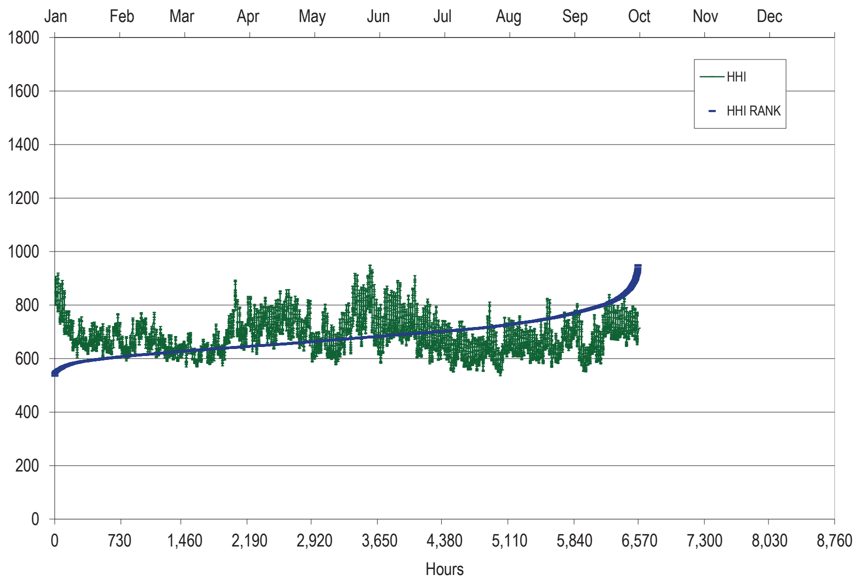


150 The installed capacity (ICAP) used for wind and solar units here is their nameplate capacity in MW. In PJM's Capacity Market, the ICAP value of wind and solar units is derated from the nameplate capacity to reflect their intermittent output characteristics.

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

Figure 3-57 presents the hourly HHI values in chronological order and an HHI duration curve for the first nine months of 2023.

Figure 3-57 Real-time hourly aggregate energy market HHI: January through September, 2023



Market Based Rates

Participation in the PJM market using offers that exceed costs requires market based rate authority approved by FERC.[152] FERC reviews the market based rate authority of PJM market sellers on a triennial schedule to ensure that market sellers do not have market power or that market power is appropriately mitigated. The entire PJM region is included in the Northeast Region for purposes of the triennial review schedule. Triennial filings by utilities with market based rates authorizations must include a market power analysis or a statement that market power has been adequately mitigated under the PJM market rules. Based on Order No. 861, sellers may, in lieu of filing a market power analysis, rely on a rebuttable presumption that market monitoring and market power mitigation are sufficient to ensure competitive market outcomes.[153]

The rules specify a separate filing schedule for transmission owning utilities and nontransmission owning utilities. The rules define a study period for market power analyses including four complete seasons. A study runs from December of one year through November of the following year (i.e., the period includes one complete winter season rather than splitting winter as a calendar year approach would). The study period is not relevant for companies that choose the rebuttable presumption option.

The most recent triennial review filings for nontransmission owning utilities in PJM were filed in June 2023. The applicable study period for the June 2023 filings, ran from December 1, 2020, to November 30, 2021. Triennial review filings for transmission owners in PJM were filed in December 2022. The applicable study period for the December 2022 filings ran from December 1, 2020, to November 30, 2021.

The MMU has recommended since 2015 that changes to the offer capping process for the energy market are needed to ensure effective market power mitigation of units that fail the TPS test. With these results and the supporting evidence, the MMU challenged the rebuttable presumption of sufficient market power mitigation for the June 2020 and December 2022 triennial review filings by generating unit owners in PJM. The MMU recommended that generators not be allowed to rely on PJM's implementation of market power mitigation rules to ensure competitive market outcomes until improvements are made to the offer capping processes in the energy and capacity markets so that suppliers cannot exercise market power.[154] In 2021, FERC issued orders requiring review of the adequacy of the market power mitigation rules and their implementation in the capacity and energy markets.[155] [156] FERC addressed the capacity market Market Seller Offer cap later in 2021.[157]

152 See *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252 (2007), *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, 123 FERC ¶ 61,055, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, 125 FERC ¶ 61,326 (2008), *order on reh'g*, Order No. 697-C, 127 FERC ¶ 61,284 (2009), *order on reh'g*, Order No. 697-D, 130 FERC ¶ 61,206 (2010), *aff'd sub nom.* Mont. Consumer Counsel v. FERC, 659 F.3d 910 (9th Cir. 2011).

153 *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040 (2019) ("Order No. 861").

154 See Protest of the Independent Market Monitor for PJM, Docket No. ER10-1556 et al. (August 28, 2020); Comments of the Independent Market Monitor for PJM, Docket No. ER10-1618-018 et al. (February 13, 2023).

155 See 175 FERC ¶ 61,231 (2021).

156 See 174 FERC ¶ 61,212 (2021).

157 See 176 FERC ¶ 61,137 (2021), *reh'g denied*, 178 FERC ¶ 61,121 (2022), *appeal pending*.

Merger Reviews

FERC reviews proposed 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."[158] [159]

FERC applies tests set forth in the 1996 Merger Policy Statement.[160] [161] 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. FERC continues to use the 1992 Guidelines even after the Department of Justice modified its guidelines in 2010.[162] Following the 1992 Guidelines, FERC applies a five step framework, which includes: defining the market; analyzing market concentration; analyzing mitigative effects of new entry; assessing efficiency gains; and assessing viability of the parties without a merger. FERC also evaluates a Competitive Analysis Screen.

The MMU reviews proposed mergers based on analysis of the impact of the merger or acquisition on market power given actual market conditions. The analysis includes use of the three pivotal supplier test results in the real-time energy market. The MMU's review ensures that mergers are evaluated based on their impact on local market power in the PJM energy market using actual observed market conditions, actual binding constraints and actual congestion results. This is in contrast to the typical merger filing that uses predefined local markets based on historical conditions that no longer exist rather than the actual local markets based on current and potential market conditions. The MMU files comments including such analyses.[163] The MMU has proposed that FERC adopt this approach when evaluating mergers in PJM.[164] FERC has considered the MMU's analysis in reviewing mergers but continues to apply a definition of markets based on an outdated and static definition of relevant markets in PJM.[165]

Neither the MMU's analysis nor the FERC defined analysis is an adequate replacement for effective market power mitigation, because system conditions are dynamic and any owner can become pivotal at any time. FERC routinely approves mergers and acquisitions and grants Market Based Rates authority to PJM market sellers despite known issues in the market power mitigation process that allow market sellers to exercise their market power.

The MMU also reviews transactions that involve ownership changes of PJM generation resources that are submitted to the Commission pursuant to section 203 of the Federal Power Act. Table 3-93 shows transactions that involved entire resources that were completed in the first nine months of 2023, as reported to the Commission. Table 3-94 shows transactions that involved transfers of partial unit ownership that were completed in the first nine months of 2023, as reported to the Commission.[166]

158 18 U.S.C. § 824b.

159 In February 2019, in response to 2017 amendments to Section 203 of the Federal Power Act, the Commission issued Order No. 855, implementing a $10,000,000 minimum value for transactions requiring the Commission's review. See 166 FERC ¶ 61,120 (2019)

160 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).

161 FERC has an open but inactive docket where the guidelines are under review. See 156 FERC ¶ 61,214 (2016); FERC Docket No. RM16-21-000.

162 See 138 FERC ¶ 61,109 (2012).

163 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); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC20-49 (June 1, 2020).

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

165 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).

166 The transaction completion date is based on the notices of consummation submitted to the Commission.

Table 3-93 Completed transfers of entire resources: January through September, 2023

Generator or Generation Owner Name	From	To	Transaction Completion Date	Docket
Summersville Hydro	Hull Street Energy, LLC	LS Power Development, LLC	January 5, 2023	EC23-22
South Jersey Industries, Inc (Marina Energy Solar)	South Jersey Industries, Inc	IIF US Holding 2	February 7, 2023	EC22-60
Energy Power Investment Company, LLC (Community Refuse Landfill, Eastern Landfill, Frey Farm Landfill, Lycoming Landfill, Northern Tier Landfill, Pennsauken Solar, Warren County Solar, I-95 Landfill, MRPC Project Landfill, Ocean Energy Project Landfill)	North American Sustainable Energy GP I, LLC and Energy Power Partners GP I, LLC	NextEra Energy, Inc	March 21, 2023	EC23-36
Shawville Generating Facility	Public Service Enterprise Group Incorporated	GenOn Holdings, Inc.	March 28, 2023	EC23-46
McHenry Battery Storage	EDF Renewables, Inc	Cordelio USA	April 28, 2023	EC23-27
Talen Energy Supply, LLC (Brandon Shores, Brunner Island, Camden Plant Holding LLC, Herbert A Wagner, Lower Mount Bethel Energy, Martins Creek, Montour, Susquehanna Nuclear)	Riverstone Holdings LLC	Rubric Capital Management LP, Nuveen Asset Management, LLC and Citadel Advisors LLC	May 17, 2023	EC23-42
Fowler II Wind, Meehoopany Wind	American Electric Power Company, Inc.	Polsky Energy Holdings LLC	May 22, 2023	EC23-66
Newark Energy Center	Ares Management Corporation	Hartree Partners L.P.	July 26, 2023	EC23-79
Pleasants Power Station	Environmental Management, LLC	Omnis Fuel Techonologies, LLC	August 1, 2023	EC23-95

Table 3-94 Completed transfers of partial ownership of resources: January through September, 2023

Generator or Generation Owner Name	Percent	From	To	Transaction Completion Date	Docket
Roth Rock Wind Farm, LLC	20.0%	Acek Energías Renovables, S.L. and Clear Wind Eólica, S.L.	ORIX Corporation	February 14, 2023	EC23-37
Jackson Generation, LLC	49.0%	Jackson Capital, LLC	Gulf Energy USA, LLC	February 27, 2023	EC23-3
RWE Porfolio (Hardin Wind, Pleasant Hill Solar, Radford's Run Wind, Stony Creek Wind, Water Strider Solar, Watlington Solar, Wildcat Wind)	9.1%	RWE Aktiengesellschaf	Qatar Holding LLC	March 15, 2023	EC23-35
Panda Patriot Generation Plant, Panda Liberty Generation Plant	25.0%	The Carlyle Group	BCPG PLC	July 12, 2023	EC23-82

The MMU has also reached agreements to mitigate market power in cases where market power concerns have been identified.[167] Such mitigation is designed to mitigate behavior over the long term, in addition to or instead of structural mitigation in the form of asset divestiture requirements.

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 singly 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. The identification of jointly pivotal suppliers as a source of market power does not require an assumption that the suppliers collude. There are multiple mechanisms that would permit the exercise of market power when there are limited suppliers providing relief to a constraint. FERC Order No. 697 also recognizes this explicitly in the discussion of HHI and pivotal suppliers.[168] FERC's definition of highly concentrated markets, based on an HHI greater than 1800, includes between five and six owners with equal market shares.

167 See 138 FERC ¶ 61,167 at P 19 (2012). The Maryland PSC accepted without condition or modification the settlement between Constellation and the MMU at the February 1, 2022, hearing in Case No. 9271. See *In the Matter of the Merger of Exelon Corporation and Constellation Energy Group, Inc.*, Order No. 90084, Order Approving 2021 Settlement Agreement and Denying Request to Require Exelon to Remain In PJM, Case No. 9271 (February 22, 2022). By its terms, the settlement became effective on February 1, 2022.
168 Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 104–117.

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 always correct, as demonstrated by these results. There are pivotal suppliers in the aggregate energy market.

The existing market power mitigation measures do not address aggregate market power.[169] Aggregate market power should be mitigated in the PJM day-ahead and real-time markets when the three pivotal supplier test is failed.

Day-Ahead Energy Market Aggregate Pivotal Suppliers

To assess the number of aggregate 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. 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.

169 One supplier, Exelon Generating Company, LLC, is partially mitigated for aggregate market power through a settlement agreement with the MMU filed December 30, 2021 and approved by the Maryland Public Service Commission as a condition of its merger. *In the Matter of the Merger of Exelon Corporation and Constellation Energy Group, Inc.*, Order No. 90084, Maryland PSC Case No. 9271 (February 22, 2022). Order No. 90084 replaces the original 10 year settlement in this case included as a condition in Order No. 84698, issued February 17, 2012, which approved the merger between Exelon and Constellation Energy Group.

Figure 3-58 shows the number of days in 2022 and the first nine months of 2023 with one aggregate pivotal supplier, two aggregate jointly pivotal suppliers, and three aggregate jointly pivotal suppliers for the day-ahead energy market. Multiple suppliers were singly pivotal on the summer peak days of 2022 and 2023. One supplier was singly pivotal on June 15 and 16, 2022, December 25, 2022, and July 27, 2023. Two suppliers were jointly pivotal on 77 days in the first nine months of 2022 and on 55 days in the first nine months of 2023. Three suppliers were jointly pivotal on 215 days in the first nine months of 2022 and 155 days in the first nine months of 2023, despite average HHIs at persistently unconcentrated levels. In 2022 and 2023, the highest levels of aggregate market power occurred in the third quarter, PJM's summer peak load season.

Figure 3-58 Days with pivotal suppliers and numbers of pivotal suppliers in the day-ahead energy market by quarter

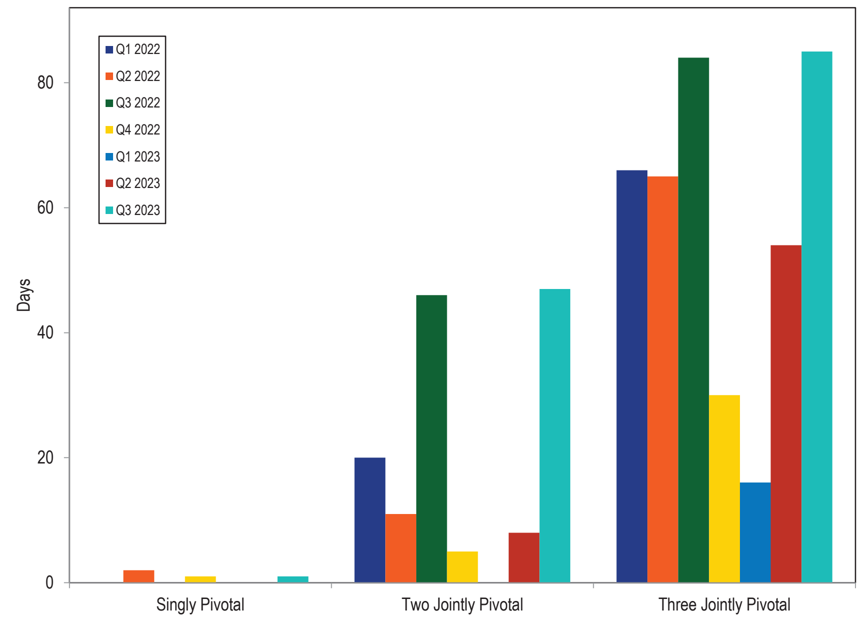


Table 3-95 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the day-ahead energy market in the first nine months of 2023. All of the top 10 suppliers were one of three pivotal suppliers on at least 80 days in the first nine months of 2023 (29.3 percent of the days).

Table 3-95 Day-ahead market pivotal supplier frequency: January through September, 2023

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%	51	18.7%	152	55.7%
2	0	0.0%	51	18.7%	149	54.6%
3	0	0.0%	47	17.2%	153	56.0%
4	0	0.0%	46	16.8%	143	52.4%
5	0	0.0%	35	12.8%	151	55.3%
6	0	0.0%	16	5.9%	113	41.4%
7	0	0.0%	7	2.6%	107	39.2%
8	0	0.0%	7	2.6%	102	37.4%
9	0	0.0%	7	2.6%	80	29.3%
10	0	0.0%	6	2.2%	93	34.1%

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.[170] 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, also called 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.

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 when the system solution indicates that a transmission constraint is binding or requires the commitment of additional resources. 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 2023, in the day-ahead energy market, the 500 kV system, 18 zones, and PJM/MISO experienced congestion resulting from one or more constraints binding for 75 or more hours, or resulting from a binding interface constraint (Table 3-976).[171] Table 3-96 shows that the 500 kV system, 12 zones and PJM/MISO experienced congestion resulting from

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

171 A constraint is mapped to the 500 kV system if its voltage is 500 kV and it is located in one of the zones including AECO, BGE, DPL, JCPLC, MEC, PECO, PENELEC, PEPCO, PPL and PSEG. All PJM/MISO reciprocally coordinated flowgates (RCF) are mapped to MISO regardless of the location of the flowgates. All PJM/NYISO RCF are mapped to NYISO as location regardless of the location of the flowgates.

one or more constraints binding for 75 or more hours or resulting from a binding interface constraint in every year from January through September, 2014 through 2023. Two zones did not experience congestion resulting from one or more constraints binding for 75 or more hours or resulting from any binding interface constraint in any year from January through September, 2014 through 2023.[172]

Table 3-96 Day-ahead congestion hours resulting from one or more constraints binding for 75 or more hours: January through September, 2014 through 2023

	(Jan - Sep)									
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
500 kV System	19,798	7,707	4,822	6,301	3,681	4,544	4,741	1,896	2,014	971
ACEC	1,611	2,578	5,037	1,686	2,530	4,631	1,955	824	144	1,057
AEP	84,506	24,112	44,324	42,657	13,586	13,085	8,960	4,240	3,309	6,372
APS	14,402	4,168	9,508	9,206	2,382	2,153	3,204	2,442	1,223	1,508
ATSI	6,625	3,289	3,616	3,848	3,186	1,574	184	0	79	497
BGE	9,517	6,715	11,245	7,433	4,561	3,521	4,716	3,159	993	4,000
COMED	45,457	13,333	36,185	46,042	10,796	3,932	2,949	1,515	2,124	3,186
DAY	921	76	671	345	300	76	919	220	0	208
DEOK	19,382	6,085	7,658	5,820	2,393	1,124	218	517	485	583
DLCO	2,633	979	200	106	198	0	0	0	97	0
DOM	9,064	6,167	4,196	4,755	2,353	727	2,214	1,962	3,646	2,705
DPL	14,203	7,655	12,960	8,691	8,974	6,702	5,006	3,371	2,302	3,591
DUKE	0	0	0	0	0	0	0	0	0	0
DUQ	0	0	0	0	0	0	0	0	0	0
EKPC	0	0	3,145	1,020	440	0	80	0	0	163
EXT	616	1,360	0	440	0	0	0	0	0	0
JCPLC	5,408	2,941	3,476	2,042	1,030	286	1,648	0	280	1,722
MEC	2,651	1,792	4,411	4,522	3,425	2,378	1,974	1,359	1,986	1,673
NYISO	0	0	0	515	0	0	0	0	0	0
OVEC	0	0	0	0	0	1,170	2,410	80	517	1,454
PE	11,425	4,881	8,606	17,758	7,485	2,739	3,256	681	3,216	3,829
PECO	7,339	3,240	5,115	8,840	2,643	1,218	917	1,333	3,349	4,404
PEPCO	1,003	699	276	643	116	79	0	0	228	364
PJM/MISO	29,744	20,244	17,250	18,558	14,699	7,450	4,514	4,334	7,949	4,742
PPL	9,010	165	2,175	6,095	3,193	7,328	4,142	3,942	4,707	2,252

In the first nine months of 2023 in the real-time energy market, the 500 kV system, ten zones, and PJM/MISO experienced congestion resulting from one or more constraints binding for 75 or more hours, or resulting from a binding interface constraint (Table 3-97).[173] Table 3-97 shows that the 500 kV system, six zones and PJM/MISO experienced congestion resulting from one or more constraints binding for 75 or more hours or resulting from a binding interface constraint in every year from January through September, 2014 through 2023. Five zones did not experience congestion resulting from one or more constraints binding for 75 or more hours or resulting from any binding interface constraint in any year from January through September, 2014 through 2023.[174]

Table 3-97 Real-time congestion hours resulting from one or more constraints binding for 75 or more hours: January through September, 2014 through 2023

	(Jan - Sep)									
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
500 kV System	1,966	646	515	810	1,009	2,777	2,075	748	869	375
ACEC	0	96	413	0	94	97	0	0	0	0
AEP	1,452	1,656	441	469	1,170	381	887	976	311	534
APS	170	356	157	136	184	0	319	888	82	0
ATSI	310	299	0	133	814	0	0	0	78	78
BGE	1,668	2,925	4,227	1,297	2,144	533	2,040	1,374	495	1,993
COMED	1,227	907	2,588	913	522	78	856	762	865	600
DAY	0	0	0	0	0	0	0	181	0	0
DEOK	0	0	0	0	75	0	0	176	0	0
DLCO	223	368	0	0	0	0	0	0	0	0
DOM	77	1,008	553	80	136	91	780	488	1,455	416
DPL	338	731	1,991	326	398	0	0	144	0	84
DUKE	0	0	0	0	0	0	0	0	0	0
DUQ	0	0	0	0	0	0	0	0	0	0
EKPC	0	0	0	0	184	0	0	0	0	0
EXT	0	0	0	778	0	0	0	0	0	0
JCPLC	0	79	0	94	0	0	0	0	0	0
MEC	0	111	0	0	553	278	730	302	771	190
NYISO	128	173	730	332	0	0	0	0	0	0
OVEC	0	0	0	0	0	0	0	0	0	0
PE	1,966	1,282	141	1,541	1,114	1,013	1,950	586	1,522	2,144
PECO	791	721	657	1,312	537	224	284	612	2,134	2,552
PEPCO	0	0	0	0	0	0	0	0	0	0
PJM/MISO	4,559	3,455	2,983	3,797	3,060	3,035	2,453	2,458	6,015	3,431
PPL	107	114	242	563	0	748	460	751	1,582	91
PSEG	1,064	1,577	170	160	211	164	0	759	330	0
REC	0	0	0	0	0	0	0	0	0	0

172 The constraint data for September 2021 through September 2023 is based on the dispatch run.

173 A constraint is mapped to the 500 kV system if its voltage is 500 kV and it is located in one of the zones including AECO, BGE, DPL, JCPLC, MEC, PECO, PENELEC, PEPCO, PPL and PSEG. All PJM/MISO reciprocally coordinated flowgates (RCF) are mapped to MISO regardless of the location of the flowgates. All PJM/NYISO RCF are mapped to NYISO as location regardless of the location of the flowgates.

174 The constraint data for September 2021 through September 2023 is based on the dispatch run.

In the PJM Day-Ahead Energy Market, the TPS test is performed in PROBE, as part of the unit commitment process. Table 3-98 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 the TPS test for the interface constraints in the PJM Day-Ahead Energy Market.

Table 3-98 Day-ahead three pivotal supplier test details for internal interface constraints: January through September, 2023

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005	Peak	0	0	0	0	0	0
	Off Peak	1	246	191	19	0	19
AEP - DOM	Peak	19	461	226	13	4	10
	Off Peak	17	592	292	15	0	15
AP South	Peak	61	317	440	23	9	14
	Off Peak	22	587	1,802	36	22	14
Bedington - Black Oak	Peak	26	113	171	19	8	12
	Off Peak	14	177	360	28	14	14
East	Peak	0	0	0	0	0	0
	Off Peak	1	139	1,241	10	10	0

Table 3-99 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, whether the TPS test was applied, and the average number of owners passing and failing the TPS test for the 10 constraints that were binding for the most hours in the day-ahead energy market. In the day-ahead energy market, the TPS test evaluates each constraint that was binding for each hour during the operating day after the initial unit commitment run. The set of constraints that are binding in the unit commitment run, for which the TPS test is applied, is not necessarily the same as the set of constraints that bind in the final day-ahead energy market solution. This is because PJM's day-ahead market is solved in three stages, and the initial set of constraints is from the Resource Scheduling and Commitment (RSC) (unit commitment) stage while the final set of binding constraints is from the Scheduling Pricing and Dispatch (SPD) (unit dispatch) stage.[175] The PJM approach fails to apply the TPS test to market sellers that provide relief to constraints in the final dispatch solution, and therefore fails to mitigate such sellers for market power.

Table 3-99 shows that two of the top 10 binding constraints in the day-ahead energy market were not tested for local market power in the first nine months of 2023 (DOEx, and Mountain). The MMU recommends that PJM modify the process for applying the TPS test in the day-ahead energy market to ensure that all local markets created by binding constraints are tested for market power and to ensure that market sellers with market power are appropriately mitigated to their competitive offers.

Table 3-99 Day-ahead three pivotal supplier test details for top 10 congested constraints: January through September, 2023

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Nottingham	Peak	1,603	199	352	27	16	11
	Off Peak	1,240	146	310	23	14	8
Easton - Emuni	Peak	33	110	6	2	0	2
	Off Peak	19	60	12	2	0	2
Allen - R.P. Mone	Peak	228	191	331	18	7	11
	Off Peak	246	253	362	19	6	13
Sayreville - Sayreville	Peak	10	18	5	1	0	1
	Off Peak	8	99	1	1	0	1
Graceton - Safe Harbor	Peak	956	219	221	22	5	16
	Off Peak	1,268	175	282	22	10	12
Gardners - Texas Eastern	Peak	691	113	18	4	0	4
	Off Peak	306	146	21	4	0	4
DoeX530	Peak	0	0	0	0	0	0
	Off Peak	0	0	0	0	0	0
Garrett - Garrett Tap	Peak	53	23	4	2	0	2
	Off Peak	0	0	0	0	0	0
Mountain	Peak	0	0	0	0	0	0
	Off Peak	0	0	0	0	0	0
Conastone - Northwest	Peak	538	243	330	26	10	15
	Off Peak	317	239	388	27	14	13

175 *See* PJM. "Manual 11: Energy & Ancillary Services Market Operations," Section 5.2.6, Rev. 126 (May 31, 2023).

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 2023.[176] While the real-time constraint hours include constraints that were binding in the five minute real-time dispatch solution (RT SCED), IT SCED, the software that performs the TPS test, may contain different binding constraints because IT SCED looks ahead to target times that are in the near future to solve for constraints that could be binding, using the load forecast for those times.[177] IT SCED solves for target times that occur at 15 minute time increments, unlike RT SCED that solves for every five minute time increment. The TPS statistics shown in this section present the data from the IT SCED TPS solution. Some IT SCED TPS solutions are used to commit units, while others are not. PJM operators have discretion in choosing which units to commit and which IT SCED results to use as the basis for the commitment and therefore which units are tested for market power using the TPS test. 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 3-100 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 interface constraints in the PJM Real-Time Energy Market. Table 3-101 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 10 constraints that were binding for the most hours in the PJM Real-Time Energy Market. Table 3-100 and Table 3-101 include analysis of all the tests for every target time where IT SCED determined that constraint relief was needed for each of the constraints shown. The same target time can be evaluated by multiple IT SCED cases at different look ahead times. Each 15 minute target time is solved by 12 different IT SCED cases at different look ahead times. The set of binding constraints for a target time may be different in 12 look ahead IT SCED solutions.

176 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>.

177 Prior to September 1, 2021, the real-time binding constraints were identical in the dispatch (RT SCED) and pricing (LPC) solutions. Beginning September 1, 2021, with implementation of fast start pricing, the set of binding constraints can differ between RT SCED and LPC pricing solutions. The set of constraints reported here are based on the binding constraints in RT SCED. This is because PJM commits and mitigates units based on a dispatch solution in IT SCED without fast start pricing.

Table 3-100 Real-time three pivotal supplier test details for internal interface constraints: January through September, 2023

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AP South	Peak	226	505	740	14	2	12
	Off Peak	233	802	867	12	1	12
PA Central	Peak	143	270	123	5	0	5
	Off Peak	37	184	37	4	0	4
West	Peak	42	424	356	12	0	12
	Off Peak	9	218	282	7	0	7

Table 3-101 Real-time three pivotal supplier test details for top 10 congested constraints: January through September, 2023

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Nottingham	Peak	52,418	137	160	12	2	10
	Off Peak	39,831	117	134	11	1	9
Lenox - North Meshoppen	Peak	24,943	19	21	3	0	3
	Off Peak	35,591	18	21	2	0	2
Graceton - Safe Harbor	Peak	19,403	114	106	10	1	9
	Off Peak	31,585	96	110	10	1	9
Weedman - Mahomet	Peak	100	19	7	2	0	2
	Off Peak	5,871	21	6	2	0	2
Chicago Ave - Praxair	Peak	8,044	18	13	3	0	3
	Off Peak	2,044	20	14	4	0	4
Conastone - Northwest	Peak	6,769	161	243	15	7	9
	Off Peak	11,392	136	221	14	7	7
Turkey Hill - Hilgard	Peak	9,133	23	13	2	0	2
	Off Peak	1,536	22	13	3	0	3
Mahomet - OCB	Peak	2,294	27	7	2	0	2
	Off Peak	4,087	30	6	2	0	2
Prest - Tibb	Peak	4,285	18	9	2	0	2
	Off Peak	1,692	21	12	3	0	3
East Towanda - Hillside	Peak	2,112	72	87	2	0	2
	Off Peak	4,250	70	89	2	0	2

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 unit offers 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 or the outcome of the TPS test in real time. Steam unit offers that are not offer capped in the day-ahead energy market continue to not be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time.[178] 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, 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.

Units committed in the day-ahead market often fail the TPS test in the real-time market when they are redispatched to provide relief to transmission constraints, even though they did not fail the TPS test in the day-ahead market. Day-ahead committed units are not evaluated for offer capping in real-time unless they update their cost-based offer. These units are able to set prices with a positive markup in the real-time market. Units that cleared the day-ahead market on their price based schedule were evaluated to identify the units whose offers were mitigated in real-time and the units that cleared on price offers in real-time despite failing the real-time TPS test. Table 3-102 shows that 2.9 percent of unit hours that cleared the day-ahead market on their price based offer were switched to cost in real-time. Table 3-102 shows that 10.1 percent of unit hours that cleared the day-ahead market on their price based offer cleared on their price based offer in real-time despite failing the real-time TPS test.

Table 3-102 Day-ahead units committed on price-based offers that cleared real-time: January through September, 2022 and 2023

	Day Ahead Price Based Unit Hours That Cleared Real-Time			Percent Day Ahead Price Based Unit Hours That Cleared Real-Time	
Year (Jan-Sep)	On Cost	On Price	On Price and Failed TPS Test	On Cost	On Price and Failed TPS Test
2022	25,111	1,948,936	219,501	1.3%	11.1%
2023	58,508	1,926,469	200,586	2.9%	10.1%

The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market.

Table 3-103 and Table 3-104 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 in the real-time energy market. Tests where there was at least one offline unit or an online unit eligible for offer capping are considered tests that could have resulted in offer capping. PJM operators also manually commit units for reliability reasons other than providing relief to a binding constraint. Manual commitments are offer capped along with resources that fail the TPS test.

Table 3-103 Summary of real-time three pivotal supplier tests applied for internal interface constraints: January through September, 2023

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	226	226	100%	9	4%	4%
	Off Peak	233	233	100%	1	0%	0%
PA Central	Peak	143	129	90%	0	0%	0%
	Off Peak	37	13	35%	0	0%	0%
West	Peak	42	42	100%	0	0%	0%
	Off Peak	9	9	100%	0	0%	0%

178 If a steam unit were to lower its cost-based offer in real time, it would become eligible for offer capping based on the online TPS test.

Table 3-104 Summary of real-time three pivotal supplier tests applied for top 10 congested constraints: January through September, 2023

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
Nottingham	Peak	52,418	51,726	99%	428	1%	1%
	Off Peak	39,831	38,895	98%	318	1%	1%
Lenox - North Meshoppen	Peak	24,943	20,798	83%	4	0%	0%
	Off Peak	35,591	14,383	40%	0	0%	0%
Graceton - Safe Harbor	Peak	19,403	19,067	98%	215	1%	1%
	Off Peak	31,585	31,161	99%	203	1%	1%
Weedman - Mahomet	Peak	5,871	1,681	29%	0	0%	0%
	Off Peak	8,044	1,671	21%	0	0%	0%
Chicago Ave - Praxair	Peak	2,044	899	44%	0	0%	0%
	Off Peak	6,769	4,387	65%	0	0%	0%
Conastone - Northwest	Peak	11,392	11,368	100%	152	1%	1%
	Off Peak	9,133	9,036	99%	53	1%	1%
Turkey Hill - Hilgard	Peak	1,536	42	3%	0	0%	0%
	Off Peak	2,294	6	0%	0	0%	0%
Mahomet - OCB	Peak	4,087	826	20%	0	0%	0%
	Off Peak	4,285	1,213	28%	0	0%	0%
Prest - Tibb	Peak	1,692	62	4%	0	0%	0%
	Off Peak	2,112	4	0%	0	0%	0%
East Towanda - Hillside	Peak	4,250	3,118	73%	1	0%	0%
	Off Peak	3,482	1,387	40%	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, like voltage support and N-2 contingencies, for providing black start and for providing 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.

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 are also issues with the absence of a TPS test under some conditions. 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. There is no tariff or manual language that defines the PJM process for evaluating units for multi-day commitments in the day-ahead 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. Under the current approach, operating parameters are tied to the cost parameters (startup cost, no load cost, and incremental energy offer). The day-ahead energy market selects which schedule to use for a resource that failed the TPS test based on its objective of clearing resources to meet the total demand at the lowest bid production cost for the system over the 24 hour period. True least system production cost can be achieved using an approach in which operating parameters and offer parameters are independently evaluated.

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.[179]

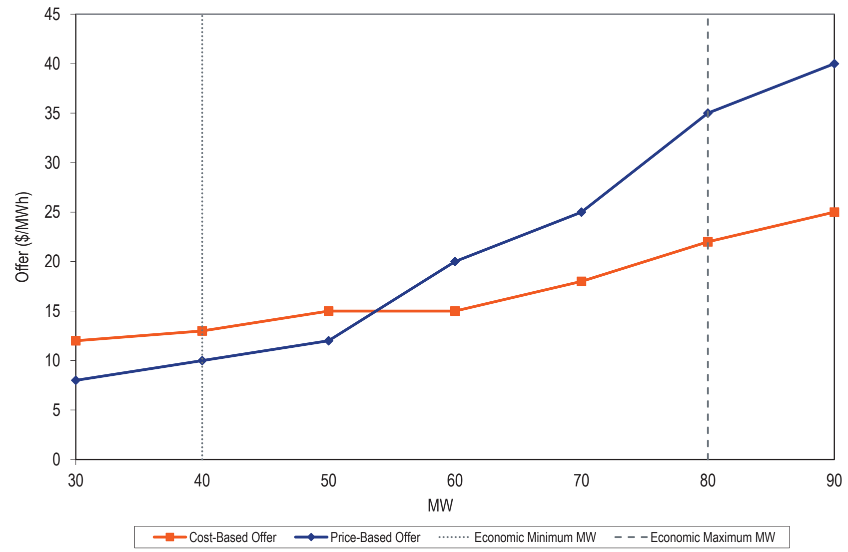
$$\text{Total Dispatch Cost} = \text{Startup Cost} + \sum_{\text{Min Run}} \text{Hourly Dispatch Cost}$$

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

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

The hourly dispatch cost is calculated only at the economic minimum level and not at higher output levels. Given the ability to submit offer curves with different 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 3-59 shows an example of offers from a unit that has a negative markup at the economic minimum MW level and a positive markup at the economic maximum MW level. The result would be that a unit that failed the TPS test would be committed on its price-based offer that has a lower dispatch cost, even though the price-based offer is higher than cost-based offer at higher output levels and includes positive markups, inconsistent with the explicit goal of local market power mitigation.

Figure 3-59 Offers with varying markups at different MW output levels



179 See OA Schedule 1 § 6.4.1(g).

Table 3-105 shows the number and percent of unit schedule hours, by month, when unit offers included crossing curves in the PJM Day-Ahead and Real-Time Energy Markets in the first nine months of 2023. The analysis only includes units that offer both price-based and cost-based offers. Units in PJM are only required to submit cost-based offers, but they may elect to offer price-based offers.

Table 3-105 Units offered with crossing curves: January through September, 2023

	Day-Ahead			Real-Time		
2023	Number of Schedule Hours with Crossing Curves	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Crossing Curves	Number of Schedule Hours with Crossing Curves	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Crossing Curves
Jan	83,060	839,544	9.9%	67,737	777,827	8.7%
Feb	72,470	764,688	9.5%	59,552	713,752	8.3%
Mar	77,731	847,714	9.2%	64,000	737,532	8.7%
Apr	79,356	825,768	9.6%	56,092	662,180	8.5%
May	89,248	854,184	10.4%	71,862	721,953	10.0%
Jun	97,311	820,800	11.9%	88,094	757,716	11.6%
Jul	107,893	843,672	12.8%	96,272	791,729	12.2%
Aug	96,943	834,504	11.6%	90,466	787,294	11.5%
Sep	88,052	812,712	10.8%	78,904	738,903	10.7%
Total	558,803	4,991,640	11.2%	481,690	4,459,775	10.8%

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 have a price-based offer with a positive markup, but have a shorter minimum run time (MRT) in the price-based offer resulting in a lower dispatch cost for the price-based offer but setting prices at a level that includes a positive markup. Table 3-106 shows the number and percent of unit schedule hours when units offered lower minimum run times in price-based offers than in cost-based offers while having a positive markup in the price based offer.

Table 3-106 Units offered with lower minimum run time on price compared to cost and with positive markup: January through September, 2023

	Day-Ahead			Real-Time		
2023	Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost
Jan	10,896	839,544	1.3%	9,618	777,827	1.2%
Feb	3,480	764,688	0.5%	2,661	713,752	0.4%
Mar	2,972	847,714	0.4%	2,498	737,532	0.3%
Apr	3,432	825,768	0.4%	3,097	662,180	0.5%
May	3,432	854,184	0.4%	2,919	721,953	0.4%
Jun	3,600	820,800	0.4%	2,905	757,716	0.4%
Jul	3,816	843,672	0.5%	3,163	791,729	0.4%
Aug	4,536	834,504	0.5%	3,831	787,294	0.5%
Sep	4,046	812,712	0.5%	3,429	738,903	0.5%
Total	40,210	7,443,586	0.5%	34,121	6,688,886	0.5%

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 the cost-based offer. Figure 3-60 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 solely as a result of the lower economic minimum MW. 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 3-60 Offers with a positive markup but different economic minimum MW

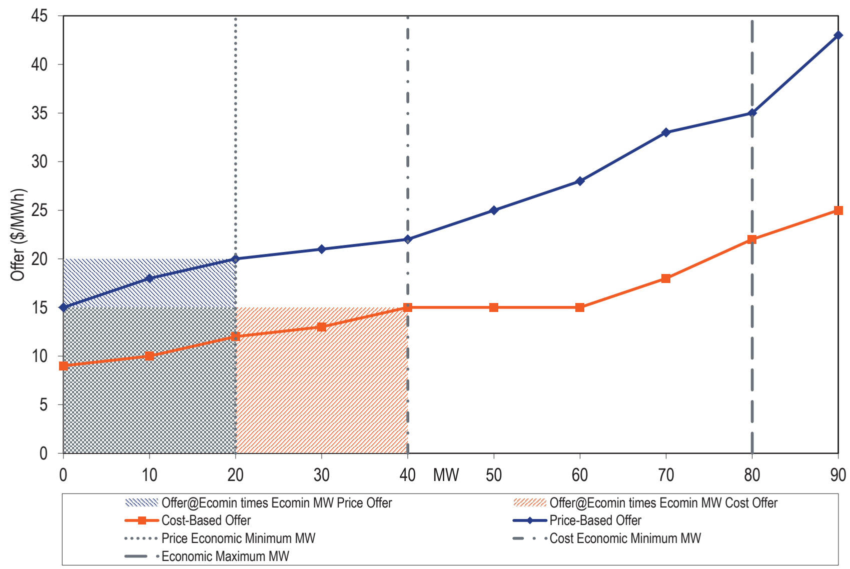


Table 3-107 shows the number and percent of unit schedule hours when units offered lower economic minimum MW in price-based offers than in cost-based offers while having a positive markup in the price-based offer.

Table 3-107 Units offered with lower economic minimum MW on price compared to cost and with positive markup: January through September, 2023

	Day-Ahead			Real-Time		
2023	Number of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Number of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost
Jan	192	839,544	0.0%	192	777,827	0.0%
Feb	144	764,688	0.0%	144	713,752	0.0%
Mar	384	847,714	0.0%	0	737,532	0.0%
Apr	72	825,768	0.0%	8	662,180	0.0%
May	120	854,184	0.0%	48	721,953	0.0%
Jun	0	820,800	0.0%	0	757,716	0.0%
Jul	0	843,672	0.0%	0	791,729	0.0%
Aug	0	834,504	0.0%	0	787,294	0.0%
Sep	0	812,712	0.0%	0	738,903	0.0%
Total	912	7,443,586	0.0%	392	6,688,886	0.0%

In the 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 cheaper even when it includes a markup. Figure 3-61 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. Table 3-108 shows the number and percent of dual fuel unit hours where the price-based offer does not have a comparable cost-based offer with a matching fuel, and the cost-based offer exceeds the price-based offer. The analysis includes only those units that offered multiple offers (cost or price) with different fuels in the first nine months of 2023.

Figure 3-61 Dual fuel unit offers

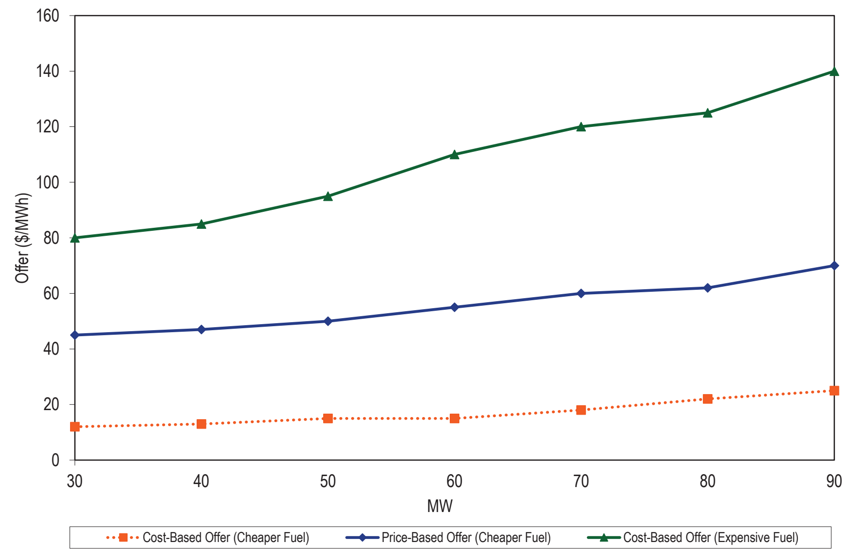


Table 3-108 Dual fuel unit offers with cost-based offers exceeding price-based offers (negative markup) but different fuel: January through September, 2023

	Day-Ahead			Real-Time		
2023	Number of Unit Hours With Negative Markup And No Matching Fuel on Cost	Total Number of Unit Hours By Units With Multiple Fuels	Percent Unit Hours With Negative Markup And No Matching Fuel on Cost	Number of Unit Hours With Negative Markup And No Matching Fuel on Cost	Total Number of Unit Hours By Units With Multiple Fuels	Percent Unit Hours With Negative Markup And No Matching Fuel on Cost
Jan	5,607	180,288	3.1%	5,607	168,984	3.3%
Feb	7,775	169,536	4.6%	7,775	158,678	4.9%
Mar	5,522	190,446	2.9%	5,522	157,797	3.5%
Apr	5,931	188,184	3.2%	5,931	150,190	3.9%
May	11,439	191,136	6.0%	11,439	169,920	6.7%
Jun	15,336	192,312	8.0%	15,336	181,141	8.5%
Jul	14,668	203,304	7.2%	14,668	194,354	7.5%
Aug	17,475	202,824	8.6%	17,475	195,290	8.9%
Sep	12,348	187,536	6.6%	12,348	180,228	6.9%
Total	96,101	1,705,566	5.6%	96,101	1,556,582	6.2%

These issues can be solved by simple rule changes.[180] The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be consistently positive or negative across the full MWh range of price and cost-based offers. This means that the cost-based and price-based offer curves never cross.[181]

PJM proposes to weaken market power mitigation as part of implementing the enhanced combined cycle modelling project. PJM's proposals would ensure that the identified issues with the implementation of market power mitigation in the energy market would never be addressed and would be exacerbated. The MMU supports proposals that would address the identified issues with the implementation of market power mitigation and would also reduce the computational time of the day-ahead market with the enhanced combined cycle model.

Levels of offer capping have historically been low in PJM, as shown in Table 3-110. 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 a transmission constraint, were subject to offer capping. Beginning November 1, 2017, under certain circumstances, online resources that are committed beyond their original commitment (day-ahead or real-time) can be offer capped if the owner fails the TPS test, and the latest available cost-based offer is determined to be lower than the price-based offer.[182] 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.

180 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.

181 See related recommendations about mitigation of operating parameters and financial offer parameters.

182 See OA Schedule 1 § 6.4.1.

The offer capping percentages shown in Table 3-109 include units that are committed to provide constraint relief whose owners failed the TPS test in the energy market, but excluding units that were committed for reliability reasons, providing black start or 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.[183] 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.

Table 3-109 Offer capping statistics – energy only: January through September, 2018 to 2023

	Real-Time		Day-Ahead	
Year (Jan-Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2018	1.0%	0.5%	0.1%	0.1%
2019	1.6%	1.1%	1.2%	0.8%
2020	1.0%	1.2%	1.6%	1.3%
2021	1.3%	1.0%	1.4%	0.8%
2022	1.3%	1.1%	1.4%	1.0%
2023	1.3%	0.9%	1.6%	0.7%

Table 3-110 shows the offer capping percentages including both units committed to provide constraint relief and units committed for reliability reasons, black start or reactive support. Reliability reasons include reactive support or local voltage support. PJM creates closed loop interfaces to, in some cases, model reactive constraints. The closed loop interface creates demand for the output of the resource needed to provide reactive power. The resulting higher LMPs in the closed loop interfaces increased economic dispatch, which contributed to the reduction in units offer capped for reactive support over time in Table 3-111. In instances where units are committed and offer capped for the modeled closed loop interface constraints, they are considered offer capped for providing constraint relief, and not for reliability.

183 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.

They are included in the offer capping percentages in Table 3-109. Prior to closed loop interfaces, these units were considered as committed for reactive support, and were included in the offer capping statistics for reliability in Table 3-111.

Table 3-110 Offer capping statistics for energy and reliability: January through September, 2018 to 2023

	Real-Time		Day-Ahead	
Year (Jan-Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2018	1.2%	0.8%	0.2%	0.4%
2019	1.6%	1.1%	1.2%	0.8%
2020	1.0%	1.2%	1.6%	1.4%
2021	1.3%	1.0%	1.4%	0.8%
2022	1.5%	1.4%	1.5%	1.1%
2023	1.4%	1.2%	1.8%	1.0%

Table 3-111 shows the offer capping percentages only for units committed for reliability reasons, black start or reactive support. The low offer capping percentages do not mean that units manually committed for reliability reasons do not have market power. All units manually committed for reliability have market power and all are treated as if they had market power. These units are not capped to their cost-based offers because they tend to offer with a negative markup in their price-based offers, particularly at the economic minimum level, which means that PJM's offer capping process results in the use of the price-based offer for commitment. However, the price-based offers have inflexible parameters such as longer minimum run times that may lead to higher total commitment cost if the unit was only needed for a shorter period that is less than its inflexible minimum run time.

Table 3-111 Offer capping statistics for reliability: January through September, 2018 to 2023

	Real-Time		Day-Ahead	
Year (Jan-Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2018	0.14%	0.29%	0.12%	0.23%
2019	0.01%	0.02%	0.01%	0.01%
2020	0.00%	0.01%	0.00%	0.00%
2021	0.02%	0.04%	0.02%	0.02%
2022	0.15%	0.27%	0.06%	0.12%
2023	0.13%	0.23%	0.17%	0.27%

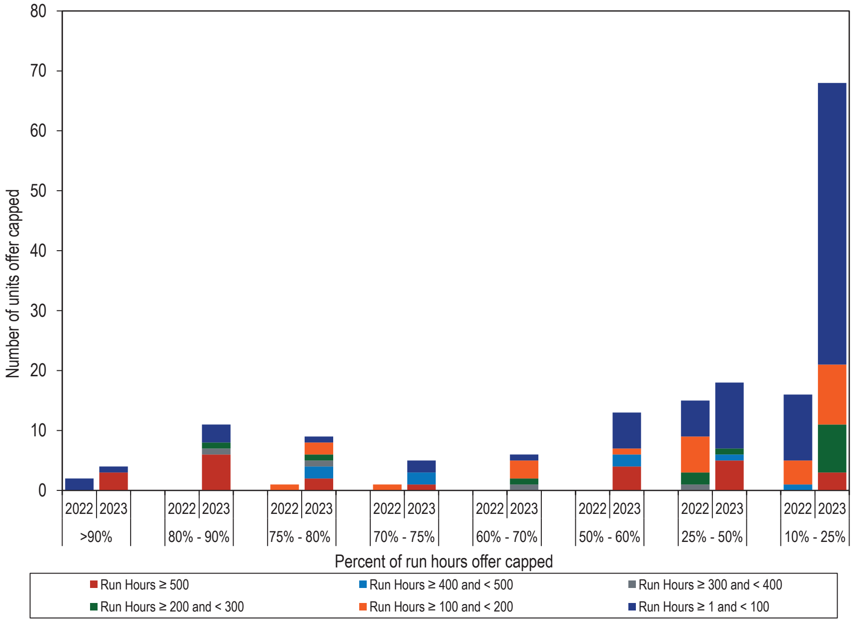
Table 3-112 presents data on the frequency with which units were offer capped in the first nine months of 2022 and 2023 as a result of failing the TPS test to provide energy for constraint relief in the real-time energy market, or for reliability reasons. Table 3-112 shows that five units were offer capped for 90 percent or more of their run hours in the first nine months of 2023, all of which ran for less than 100 hours, compared to 14 units with 90 percent or more offer capped run hours in the first nine months of 2022, eight of which ran for less than 100 hours.

Table 3-112 Real-time offer capped unit statistics: January through September, 2022 and 2023

		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
	2022	0	0	0	0	0	2
90%	2023	3	0	0	0	0	1
	2022	0	0	0	0	0	0
80% and < 90%	2023	6	0	1	1	0	3
	2022	0	0	0	0	1	0
75% and < 80%	2023	2	2	1	1	2	1
	2022	0	0	0	0	1	0
70% and < 75%	2023	1	2	0	0	0	2
	2022	0	0	0	0	0	0
60% and < 70%	2023	0	0	1	1	3	1
	2022	0	0	0	0	0	0
50% and < 60%	2023	4	2	0	0	1	6
	2022	0	0	1	2	6	6
25% and < 50%	2023	5	1	0	1	0	11
	2022	0	1	0	0	4	11
10% and < 25%	2023	3	0	0	8	10	47

Figure 3-62 shows the frequency with which units were offer capped in the first nine months of 2022 and 2023 for failing the TPS test to provide energy for constraint relief in the real-time energy market or for reliability reasons.

Figure 3-62 Real-time offer capped unit statistics: January through September, 2022 and 2023



In response to FERC's request for Common Metrics for 2019 through 2022, PJM filed a report stating that between 2019 and 2022 the percent of unit hours in the day-ahead energy market with active market power mitigation was between 78.8 and 100 percent, while the actual results were between 1.4 and 1.7 percent.[184] PJM also reported that between 2019 and 2022, the percent of unit intervals in the real-time energy market with active market power mitigation was between 43.3 and 53.3 percent, while the actual results were between 1.0 and 1.7 percent. PJM's reported results were incorrect because PJM provided hours of mitigation instead of unit hours or unit intervals mitigated. In the day-ahead market a mitigated unit hour is one unit mitigated for one hour. The denominator is all cleared units cleared for all hours. In the real-time market a mitigated unit interval is one unit mitigated for one interval. The denominator is all cleared units for all intervals. For example, if there were 10 units running in a given hour in the day-ahead market, if one unit was mitigated for that hour, then the percent of unit hours mitigated would be 10 percent, but PJM defined the percent mitigated as 100 percent of the hour. The PJM filed report dramatically overstated the frequency of market power mitigation in the PJM energy market. The MMU has correctly reported this metric in the State of the Market Reports for 2002 and subsequent years. The MMU also reports the MWh subject to market power mitigation which reflects the relative size of the units subject to market power mitigation.

184 See Common Performance Metrics, Docket No. AD19-16-000, PJM Compliance Filing, PJM Metrics Spreadsheet 2023 (April 17, 2023).

Markup Index

Markup is a summary measure of the degree to which a participant's offer behavior or conduct for individual units is competitive. When a seller makes a competitive offer, markup is zero. When a seller exercises market power in its offer, 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.[185] The markup index is normalized and can vary from -1.00 when the offer price is less than the cost-based offer price, to 1.00 when the offer price is higher than the cost-based offer price. 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 3-113 shows the average markup index of marginal units in the real-time energy market, by offer price category using unadjusted cost-based offers. Table 3-114 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 at the dispatch point on the offer curves. The adjusted markup is the

185 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.

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.[186] The markup is negative if the cost-based offer of the marginal unit is greater than 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.

PJM implemented Fast Start Pricing on September 1, 2021. For all the fast start marginal units beginning on September 1, 2021, the markup includes markup in the incremental offer, markup in the amortized start up offer, and markup in the amortized no load offer.

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. The PJM Market rules permit the 10 percent adder and maintenance costs, which are not short run marginal costs, under the definition of cost-based offers. Actual market behavior reflects the fact that neither is part of a competitive offer and neither is a short run marginal cost.[187]

In the first nine months of 2023, the average dollar markups of units with offer prices less than $10 was negative (-$1.52 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $10 and $15 was negative (-$0.43 per MWh) when using unadjusted cost-based offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, revealing a short run marginal cost that is less than the maximum allowable cost-based offer under the PJM Market Rules.

Some marginal units did have substantial markups. Among the units that were marginal in the first nine months of 2023, 0.9 percent had offer prices above $150 per MWh. Among the units that were marginal in the first nine months of 2022, 4.5 percent had offer prices greater than $150 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the first nine months of 2023 was more than $400, and the highest markup in the first nine months of 2022 was more than $900.

Table 3-113 Real-time average marginal unit markup index (By offer price category unadjusted): January through September, 2022 and 2023

	2022 (Jan - Sep)			2023 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	2.38	($0.86)	13.7%	(0.13)	($2.00)	18.8%
$10 to $15	(0.19)	($5.18)	0.5%	(0.07)	($1.44)	14.9%
$15 to $20	(0.14)	($3.29)	1.2%	(0.05)	($1.24)	19.9%
$20 to $25	(0.01)	($1.23)	2.0%	(0.01)	($1.14)	15.5%
$25 to $50	0.01	($0.23)	39.1%	0.01	($0.64)	26.2%
$50 to $75	0.02	$0.72	22.0%	0.18	$9.64	2.9%
$75 to $100	0.04	$2.03	10.3%	0.30	$23.81	0.7%
$100 to $125	0.09	$9.12	4.7%	0.52	$57.33	0.2%
$125 to $150	0.13	$17.53	2.0%	0.49	$63.07	0.1%
>= $150	0.09	$19.77	4.5%	0.09	$18.61	0.9%
All Offers	0.21	$1.74	100.0%	(0.03)	($0.40)	100.0%

Table 3-115 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.[188]

186 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.

187 See PJM. "Manual 15: Cost Development Guidelines," Rev. 43 (June 1, 2023).

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

Table 3-114 Real-time average marginal unit markup index (By offer price category adjusted): January through September, 2022 and 2023

	2022 (Jan - Sep)			2023 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	2.38	($0.79)	13.7%	(0.08)	($1.52)	18.8%
$10 to $15	(0.13)	($3.64)	0.5%	(0.01)	($0.43)	14.9%
$15 to $20	(0.06)	($1.52)	1.2%	0.02	$0.06	19.9%
$20 to $25	0.06	$0.78	2.0%	0.04	$0.37	15.5%
$25 to $50	0.08	$2.75	39.1%	0.08	$1.71	26.2%
$50 to $75	0.09	$5.02	22.0%	0.24	$12.99	2.9%
$75 to $100	0.11	$8.11	10.3%	0.34	$27.59	0.7%
$100 to $125	0.16	$16.87	4.7%	0.54	$60.14	0.2%
$125 to $150	0.19	$26.05	2.0%	0.49	$63.41	0.1%
>= $150	0.16	$39.56	4.5%	0.16	$37.66	0.9%
All Offers	0.27	$5.99	100.0%	0.03	$1.25	100.0%

Table 3-116 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 2023, using unadjusted cost-based offers for coal units, 52.86 percent of marginal coal units had negative markups. The share of marginal gas units with negative markups at the dispatch point on their offer curve increased from 32.40 percent in the first nine months of 2022 to 52.86 percent in the first nine months of 2023 when using unadjusted cost based offers.

Table 3-115 Percent of marginal units with markup below, above and equal to zero (By fuel type with unadjusted offers): January through September, 2022 and 2023

	2022 (Jan - Sep)			2023 (Jan - Sep)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	32.40%	16.88%	50.72%	52.86%	27.46%	19.68%
Gas	42.96%	18.00%	39.04%	48.21%	16.36%	35.43%
Oil	1.74%	98.12%	0.14%	5.02%	94.86%	0.12%

In the first nine months of 2023, using adjusted cost-based offers for coal units, 39.39 percent of marginal coal units had negative markups.

Table 3-116 Percent of marginal units with markup below, above and equal to zero (By fuel type with adjusted offers): January through September, 2022 and 2023

	2022 (Jan - Sep)			2023 (Jan - Sep)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	17.99%	8.27%	73.74%	39.39%	7.84%	52.77%
Gas	25.30%	11.37%	63.33%	35.90%	11.38%	52.72%
Oil	1.59%	97.81%	0.59%	2.77%	94.86%	2.36%

Figure 3-63 shows the frequency distribution of hourly markups for all gas units offered in the first nine months of 2022 and the first nine months of 2023 using unadjusted cost-based offers. The highest markup within the economic operating range of the unit's offer curve was used in the frequency distributions.[189] Of the gas units offered in the PJM market in the first nine months of 2023, 21.7 percent of gas unit hours had a maximum markup that was negative and 15.4 percent of gas fired unit hours had a maximum markup above $100 per MWh. The share of offered gas units with maximum markup that was negative increased in the first nine months of 2023 compared to the first nine months of 2022 and the share of marginal gas units with negative markups also increased.

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

Figure 3-63 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: January through September, 2022 and 2023

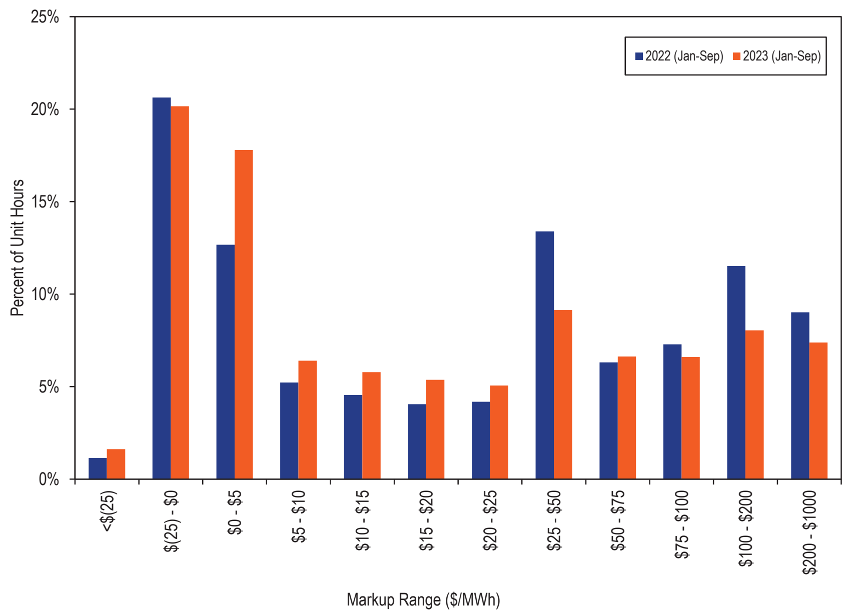


Figure 3-64 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: January through September, 2022 and 2023

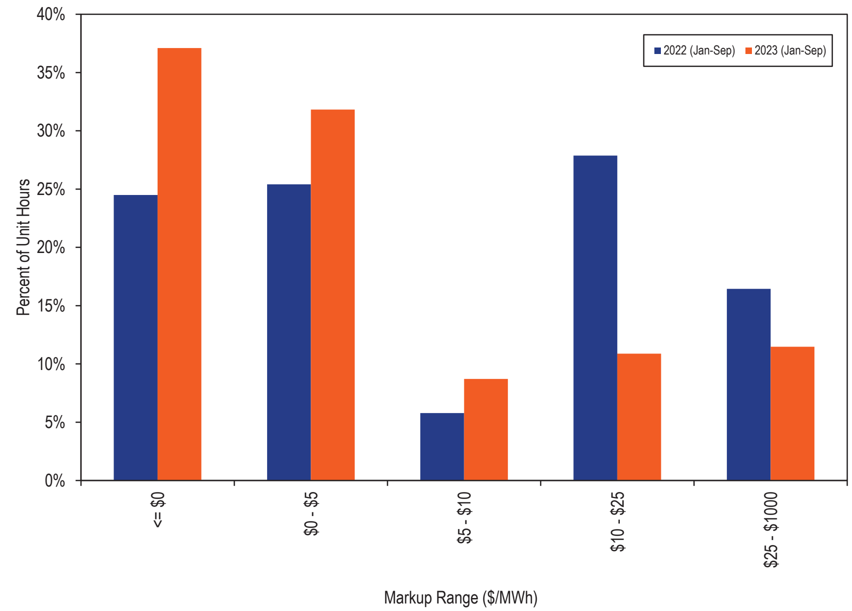
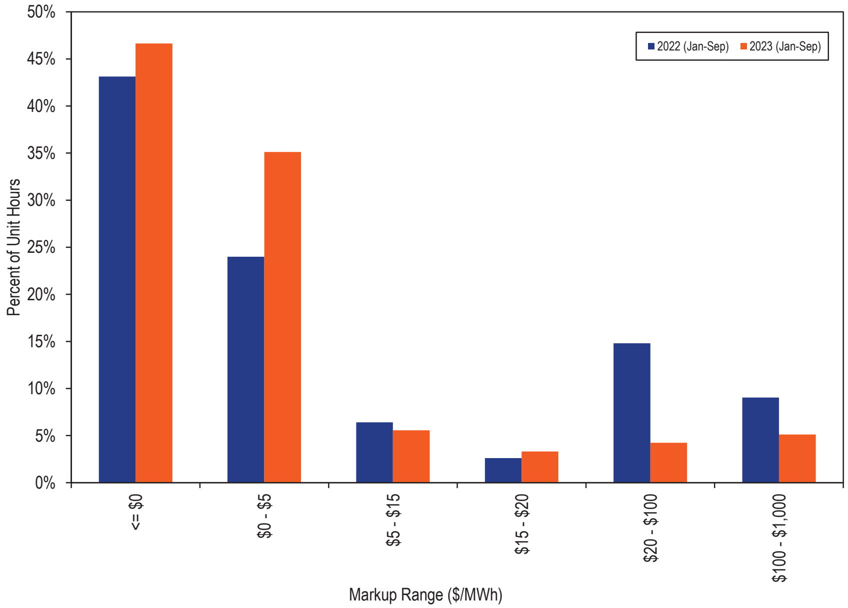


Figure 3-64 shows the frequency distribution of hourly markups for all coal units offered in the first nine months of 2022 and the first nine months of 2023 using unadjusted cost-based offers. Of the coal units offered in the PJM market in the first nine months of 2023, 37.1 percent of coal unit hours had a maximum markup that was negative or equal to zero, increasing from 24.4 percent in the first nine months of 2022. The share of offered coal units with maximum markup that was negative increased in the first nine months of 2023 and the share of marginal coal units with negative markups also increased in the first nine months of 2023 compared to the first nine months of 2022.

Figure 3-65 shows the frequency distribution of hourly markups for all offered oil units in the first nine months of 2022 and the first nine months of 2023 using unadjusted cost-based offers. Of the oil units offered in the PJM market in the first nine months of 2023, 46.6 percent of oil unit hours had a maximum markup that was negative or equal to zero. More than 5.0 percent of oil fired unit hours had a maximum markup above $100 per MWh.

Figure 3-65 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: January through September, 2022 and 2023

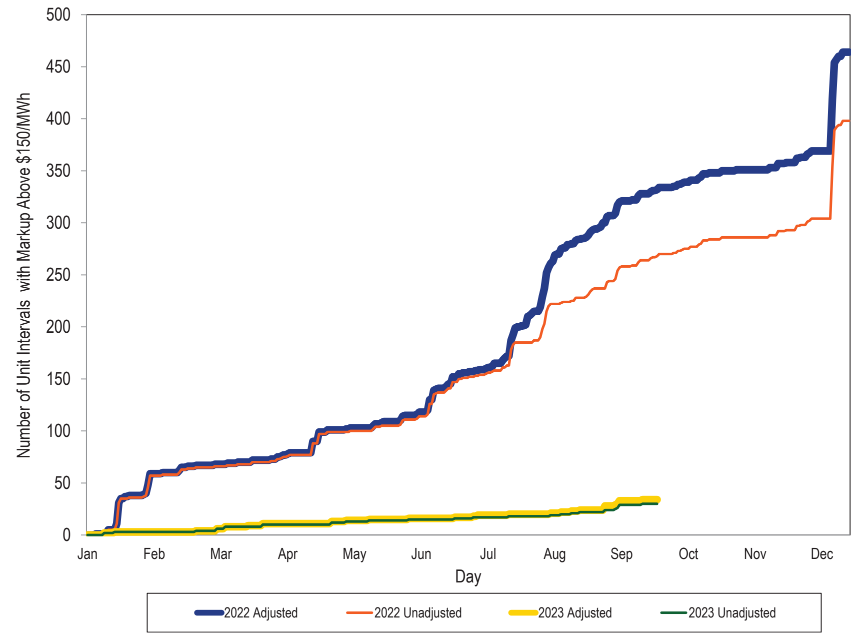


The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion 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 3-66 shows the number of marginal unit intervals in the first nine months of 2023 and the first nine months of 2022 with markup above $150 per MWh.

Figure 3-66 Cumulative number of unit intervals with markups above $150 per MWh: January through September, 2022 and 2023



Day-Ahead Markup Index

Table 3-117 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using unadjusted cost-based offers.[190]

The majority of marginal units are virtual transactions, which do not have markup. The average dollar markups of units with offer prices less than $10 was negative (-$1.24 per MWh) when using unadjusted cost-based offers.

190 The pricing run marginal resource data is used when calculating day-ahead markup index for the first nine month of 2022 and 2023.

In the first nine months of 2023, the average dollar markups of units with offer prices between $10 and $15 was positive ($3.37 per MWh) when using unadjusted cost-based offers.

Some marginal units did have substantial markups. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the day-ahead market in the first nine months of 2023 was more than $200 per MWh while the highest markup in the first nine months of 2022 was more than $300 per MWh.

Table 3-117 Average day-ahead marginal unit markup index (By offer price category, unadjusted): January through September, 2022 and 2023

	2022 (Jan-Sep)			2023 (Jan-Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	8.31	$6.90	3.9%	0.38	($1.24)	3.3%
$10 to $15	2.00	$21.72	0.9%	0.30	$3.37	4.9%
$15 to $20	0.77	$13.10	2.7%	0.28	$4.45	10.9%
$20 to $25	0.44	$8.38	2.1%	0.20	$3.35	18.2%
$25 to $50	0.13	$4.22	38.0%	0.18	$5.97	51.3%
$50 to $75	0.09	$5.17	29.4%	0.33	$18.33	8.3%
$75 to $100	0.15	$11.17	13.1%	0.24	$15.75	0.7%
$100 to $125	0.25	$26.70	5.3%	0.31	$28.85	0.4%
$125 to $150	0.24	$32.79	1.8%	0.48	$67.99	0.2%
>= $150	0.17	$30.87	2.7%	0.31	$70.61	1.9%
All Offers	0.49	$8.43	100.0%	0.22	$7.47	100.0%

Table 3-118 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 2023, 51.3 percent of day-ahead marginal generation units had offers between $25 and $50 per MWh. For units with an offer price less than $10, the average markup index decreased from 8.30 in the first nine months of 2022 to 0.41 in the first nine months of 2023.

Table 3-118 Average day-ahead marginal unit markup index (By offer price category, adjusted): January through September, 2022 and 2023

	2022 (Jan-Sep)			2023 (Jan-Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	8.30	$6.98	3.9%	0.41	($0.89)	3.3%
$10 to $15	2.03	$22.27	0.9%	0.35	$4.20	4.9%
$15 to $20	0.83	$14.12	2.7%	0.32	$5.34	10.9%
$20 to $25	0.49	$9.79	2.1%	0.24	$4.54	18.2%
$25 to $50	0.20	$7.13	38.0%	0.24	$7.98	51.3%
$50 to $75	0.15	$8.98	29.4%	0.38	$21.28	8.3%
$75 to $100	0.20	$16.52	13.1%	0.29	$21.04	0.7%
$100 to $125	0.31	$33.26	5.3%	0.36	$35.13	0.4%
$125 to $150	0.30	$40.74	1.8%	0.52	$73.81	0.2%
>= $150	0.23	$49.57	2.7%	0.37	$84.08	1.9%
All Offers	0.55	$12.42	100.0%	0.27	$9.44	100.0%

No Load and Start Cost Markup

Generator energy offers in PJM are comprised of three parts, an incremental energy offer curve, no load cost and start cost. In cost-based offers, all three parts are capped at the level allowed by Schedule 2 of the Operating Agreement, the Cost Development Guidelines (Manual 15) and fuel cost policies approved by PJM. In price-based offers, the incremental energy offer curve is capped at $1,000 per MWh (unless the verified cost-based offer exceeds $1,000 per MWh, but cannot exceed $2,000 per MWh). Generators are allowed to choose whether to use price-based or cost-based no load cost and start costs twice a year. If price-based is selected, the no load and start costs do not have a cap, but the offers cannot be changed for six months (April through September and October through March). If cost-based is selected, the cap is the same as the cap of the no load and start costs in the cost-based offers, and the offers can be updated daily or hourly based on changes in costs. Table 3-119 shows the caps on the three parts of cost-based and price-based offers.

Table 3-119 Cost-based and price-based offer caps

Offer Type	No Load and Start Cost Option	Incremental Offer Curve Cap	No Load Cost Cap	Start Cost Cap
Cost-Based	Cost-Based	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies		
Price-Based	Cost-Based	$1,000/MWh or based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies if verified cost-based offer exceeds $1,000/MWh but no more than $2,000/MWh.	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies
	Price-Based		No cap but can only be changed twice a year.	No cap but can only be changed twice a year.

Table 3-120 shows the number of units that chose the cost-based option and the price-based option. In the first nine months of 2023, 89 percent of all generators that submitted no load or start costs chose to have cost-based no load and start costs in their price-based offers, the same as in the first nine months of 2022.

Table 3-120 Number of units selecting cost-based and price-based no load and start costs: January through September, 2022 and 2023

	2022 (Jan-Sep)		2023 (Jan-Sep)	
No Load and Start Cost Option	Number of units	Percent	Number of units	Percent
Cost-Based	511	89%	486	89%
Price-Based	62	11%	63	11%
Total	573	100%	549	100%

Generators can have positive or negative markups in their no load and start costs under the price-based option. Generators cannot have positive markups in no load and start costs when they select the cost-based option. Table 3-121 shows the average markup in the no load and start costs in the first nine months of 2022 and 2023. Generators that selected the cost-based start and no load option offered on average with a negative markup on the no load cost and a negative markup on the start costs. The price-based offers were lower than the cost-based offers. Generators that selected the price-based start and no load option offered on average with a positive markup on the no load cost and with very large positive markups on the start costs.

Table 3-121 No load and start cost markup: January through September, 2022 and 2023

Period	No Load and Start Cost Option	No Load Cost	Cold Start Cost	Intermediate Start Cost	Hot Start Cost
2022 (Jan -Sep)	Cost-Based	(8%)	(8%)	(7%)	(7%)
	Price-Based	(52%)	111%	109%	129%
2023 (Jan-Sep)	Cost-Based	(7%)	(6%)	(6%)	(7%)
	Price-Based	15%	190%	177%	181%

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 2023, 6.1 percent of the marginal units set prices based on cost-based offers, 1.5 percentage points lower than in the first nine months of 2022.

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. The market rules allow these overstated cost-based offers. 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.

The efficacy of market power mitigation rules also depends on the accuracy of cost-based offers. Some unit owners use fuel cost policies that are not algorithmic, verifiable, and systematic. These inadequate fuel cost policies permit overstated fuel costs in cost-based offers.

When market power mitigation is not effective due to inaccurate cost-based offers that exceed short run marginal costs, market power causes increases in market prices above the competitive level.

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 allows for multiple interpretations, which could lead to tariff violations. The incorrect rules lead to higher energy market prices and higher uplift.

There are three types of costs identified in 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, a variable cost, is that the cost is "directly related to electric production."[191]

Variable costs, as defined in the PJM rules, 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.[192]

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, replacement of obsolete equipment, and overtime staffing costs in costs related to electric production. PJM includes taxes, preventative maintenance to auxiliary equipment, improvement of working equipment, maintenance expenses triggered by a time milestone (e.g. annual, weekly) and pipeline reservation charges in costs not related to electric production.

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 in the energy market 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 3-122 shows the status of all fuel cost policies (FCP). As of September 30, 2023, 698 units (90 percent) had an FCP passed by the MMU and 79 units (10 percent) had an FCP failed by the MMU. The units with fuel cost policies failed by the MMU represented 18,089 MW. All units' FCPs were approved by

191 See 167 FERC ¶ 61,030 (2019).

192 See OA Schedule 2 § 1.1(a).

PJM. As of September 30, 2023, 543 units did not have FCPs. Units without FCPs cannot submit nonzero cost based offers, unless they use the temporary cost method.[193]

Table 3-122 FCP Status for PJM generating units: September 30, 2023

	MMU Status			
PJM Status	Pass	Submitted	Fail	Total
Submitted	0	0	0	0
Under Review	0	0	0	0
Customer Input Required	0	0	0	0
Approved	698	0	79	777
Total	698	0	79	777

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.[194] Verifiable means that the FCP requires a market seller to 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 clearly defined quantitative method or methods for calculating fuel costs, including objective triggers for each method.[195] PJM and FERC did not agree that fuel cost policies should be algorithmic, although PJM's standard effectively requires algorithmic fuel cost policies by describing the requirements.[196] 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').[197]

193 See OA Schedule 2 § 2.1.
194 Answer of PJM Interconnection, L.L.C. to Protests and Comments, Docket No. ER16-372-002 (October 7, 2016) at P 11 ("October 7th Filing").
195 Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) at P 8 ("September 16th Filing").
196 October 7th Filing at P12; 158 FERC ¶ 61,133 at P 57 (2017).
197 September 16th Filing at P 8.

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: accuracy (reflect applicable costs accurately); and fuel contracts (reflect the market seller's applicable commodity and/or transportation contracts where it holds such contracts).[198]

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 dollars per MWh or in dollars 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 units.

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 the use of available market information that results in inaccurate and overstated expected costs. Overstated costs permit the exercise of market power.

Some of the failed fuel cost polices include the use of available market information that results in inaccurate expected costs because the information does not represent a cleared market price. 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 not a market clearing price and is 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.

198 See PJM Operating Agreement Schedule 2 § 2.3 (a).

The FCPs that failed the MMU's evaluation also fail to meet the standards defined in the PJM tariff. PJM should not have approved noncompliant fuel cost policies. The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic.

Cost-Based Offer Penalties

Market sellers are assessed penalties when they submit cost-based offers that do not comply with Schedule 2 of the PJM Operating Agreement and PJM Manual 15.[199] Penalties are assessed when both PJM and the MMU are in agreement.

In the first nine months of 2023, 59 penalty cases were identified all resulting in assessed cost-based offer penalties. These cases were for 58 units owned by 17 different companies. Table 3-123 shows the penalties by the year in which participants were notified.

Table 3-123 Cost-based offer penalty cases by year notified: May 2017 through September 2023

Year notified	Cases	Assessed penalties	Self Identified	MMU and PJM Disagreement	Pending cases	Number of units impacted	Number of companies impacted
2017	57	56	0	1	0	55	16
2018	187	161	0	26	0	138	35
2019	57	57	0	0	0	57	19
2020	142	137	24	5	0	124	25
2021	129	124	42	5	0	124	21
2022	116	116	51	0	0	110	20
2023	59	58	7	0	1	58	17
Total	747	709	124	37	1	462	72

Since 2017, 747 penalty cases have been identified, 709 resulted in assessed cost-based offer penalties, 37 resulted in disagreement between the MMU and PJM, one remains pending and 124 were self identified by market sellers. The 709 cases were from 462 units owned by 72 different companies. The total penalties were $5.2 million, charged to units that totaled 136,646 available MW. The average penalty was $1.71 per available MW. This means that a 100 MW unit would have paid a penalty of $4,111.[200] In some cases where the penalized unit operates, the increase to LMP and/or uplift due to the incorrect offer exceeds the amount of the penalty. Table 3-124 shows the total cost-based offer penalties since 2017 by year.

199 See OA Schedule 2 § 6.

200 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.

Table 3-124 Cost-based offer penalties by year: May 2017 through September 2023

Year	Number of units	Number of companies	Penalties	Average Available Capacity Charged (MW)	Average Penalty ($/MW)
2017	92	19	$556,826	16,930	$1.56
2018	127	34	$1,242,102	25,743	$2.28
2019	73	23	$378,245	15,073	$1.14
2020	140	26	$407,283	21,908	$0.85
2021	125	25	$753,463	24,808	$1.31
2022	123	22	$1,613,621	24,385	$2.76
2023	53	13	$297,193	7,799	$1.57
Total	733	67	$5,248,733	136,646	$1.71

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.

2020 Fuel Cost Policy Changes

On July 28, 2020, the Commission approved tariff revisions that modified the fuel cost policy process and the cost-based offer penalties.[201]

The tariff revisions replaced the annual review process with a periodic review set by PJM. The revisions reinstated the periodic review process employed by the MMU prior to PJM's involvement in the review and approval of fuel cost policies. Monitoring participant behavior through the use of fuel cost policies is an ongoing process that necessitates frequent updates. Market sellers must revise their fuel cost policies whenever circumstances change that impact fuel pricing (e.g. different pricing points, dual fuel addition capability).

The tariff revisions removed the requirement for units with zero marginal cost to have an approved fuel cost policy but also included a zero offer cap for cost-based offers for units that do not have an approved fuel cost policy.

201 172 FERC ¶ 61,094 (2020).

The tariff revisions allow a temporary cost offer method for units that do not have an approved fuel cost policy. The revisions allow units to submit nonzero cost-based offers without an approved fuel cost policy if they follow the temporary cost offer method. The use of the method results in cost-based offers that do not follow the fuel cost policy rules. The approach significantly weakens market power mitigation by allowing market sellers to make offers without an approved fuel cost policy. The proposed approach allows the use of an inaccurate and unsupported fuel cost calculation in place of an accurate fuel cost policy.

The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy.

The tariff revisions replace the fuel cost policy revocation provision with the ability for PJM to terminate fuel cost policies.

The tariff revisions reduce the penalties for noncompliant cost-based offers in two situations. When market sellers report their noncompliant cost-based offers, the penalty is reduced by 75 percent. When market sellers do not meet conditions defined to measure a potential market impact the penalty is reduced by 90 percent. The conditions include if the market seller failed the TPS test, if the unit was committed on its cost-based offer, if the unit was marginal or if the unit was paid uplift.

The tariff revisions eliminate penalties entirely when units submit noncompliant cost-based offers if PJM determines that an unforeseen event hindered the market seller's ability to submit a compliant cost-based offer. This new provision allows market sellers to not follow their fuel cost policy, submit cost-based offers that are not verifiable or systematic and not face any penalties for doing so.

The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy.

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 or updated 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. In 2022, PJM made updates recommended by the MMU to Manual 15 to add straightforward descriptions for some of the most essential cost offer calculations.[202]

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.[203] The changes proposed by PJM attempted but failed 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.[204] On October 28, 2019, FERC issued a final order accepting PJM's compliance filing.[205] Regardless of the changes, the rules remain unclear and are now inconsistent with economic theory and effective market power mitigation and competitive market results.

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.

202 See PJM Manual 15: Cost Development Guidelines, Revision 42 (Oct. 28, 2022).
203 See PJM Interconnection Maintenance Adder Revisions to the Amended and Restated Operating Agreement, L.L.C., Docket No. EL19-8-000.
204 167 FERC ¶ 61,030 (2019).
205 168 FERC ¶ 61,134 (2019).

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.

PJM allows for the calculation of VOM costs in dollars per MWh, dollars per MMBtu, dollars per run hour, dollars per equivalent operating hour (EOH) and dollars per start. The MMU converted all VOM costs into dollars per MWh using the units' heat rates, the average economic maximum and average minimum run time of the units in 2022.

The average variable operating and maintenance cost approved by PJM for combustion turbines and diesels in 2022 was five percent higher than the approved variable operating and maintenance cost approved by PJM in 2021.[206]

The average variable operating and maintenance cost approved by PJM for combined cycles in 2022 was two percent lower than the approved variable operating and maintenance cost approved by PJM in 2021.

The average variable operating and maintenance cost approved by PJM for coal units in 2022 was one percent lower than the approved variable operating and maintenance cost approved by PJM in 2021.

Table 3-125 shows the amount of capacity offered by range of VOM costs. Table 3-125 shows that 1,135 MW have an approved effective VOM above $100 per MWh and 1,736 MW have an approved effective VOM between $50 and $100 per MWh.

206 PJM reviews VOM once per year. The results reflect PJM's most recent review. VOM costs are effective from the approval date until December 31 of the next year.

Table 3-125 Approved effective VOM costs in dollars per MWh: 2019 through 2022

	Offered MW			
Approved VOM Range ($/MWh)	2019	2020	2021	2022
$0 to $5 per MWh	69,025	71,898	64,131	65,533
$5 to $10 per MWh	37,325	30,325	34,369	38,588
$10 to $20 per MWh	14,276	15,931	21,492	17,010
$20 to $50 per MWh	5,402	4,938	5,015	7,366
$50 to $100 per MWh	2,302	3,146	2,324	1,736
Above $100 per MWh	1,159	1,044	772	1,135

The level of costs accepted by PJM for inclusion in VOM depends on PJM's interpretation of the maintenance activities or expenses directly related to electricity production and the level of detailed support provided by market sellers to PJM.

PJM's VOM review is not adequate to determine whether all costs included in VOM are compliant. PJM's VOM review focuses only on the expenses submitted for the last year of up to 20 years of data. For example, a market seller can provide data from 2010 without any supporting documentation as long as the data from 2021 (last year) has documentation. PJM's review is dependent on the level of detail provided by the market seller. Recent changes in PJM's review process, triggered by MMU questions, required more details from market sellers and have led to the appropriate exclusion of expenses that were previously included.[207]

The flaws in PJM's review process for VOM are compounded by the ambiguity in the criteria used to determine if costs are includable. PJM's definition of allowable costs for cost-based offers, "costs resulting from electric production," is so broad as to be meaningless. Most costs incurred at a generating station result from electric production in one way or another. The generator itself would not exist but for the need for electric production. PJM's broad definition cannot identify which costs associated with electric production are includable in cost-based offers. The definition is not verifiable or systematic and permits wide discretion by PJM and generators.

207 See "Maintenance Adder & Operating Cost Submission Process," 55-57 PJM presentation to the Tech Change Forum. (April 21, 2020) <https://pjm.com/-/media/committees-groups/forums/tech-change/2020/20200421-special/20200421-item-01-maintenance-adder-and-operating-cost-submission-process.ashx>.

The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics.

The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced.

The MMU understands that companies have different document retention policies but in order to be allowed to include maintenance costs, such costs must be verified, and they cannot be verified without documentation. Supporting documentation includes internal financial records, maintenance project documents, invoices, and contracts. Market participants should be required to provide the operational data (e.g. run hours, MWh, MMBtu) that supports the maintenance cycle of the equipment being serviced/replaced. For example, if equipment is serviced every 5,000 run hours, the market participant must include at least 5,000 run hours of historical operation in its maintenance cost history.

On February 17, 2023, PJM filed tariff revisions changing the rules related to VOM costs. The changes included separating maintenance expenses into major and minor maintenance, allowing the use of default adders for minor maintenance and operating costs and eliminating the annual review requirement for units that choose to use default adders. The proposal that included the tariff changes also included Manual 15 changes that introduced additional documentation requirements. Regarding maintenance expenses, market participants will be required to provide all supporting documentation for all expenses submitted, regardless of year. Regarding operating expenses, market participants will be required to provide the amount of consumables used during operation and the cost per unit of each consumable. On April 18, 2023, FERC accepted PJM's filing.

FERC System of Accounts

PJM Manual 15 relies on the FERC System of Accounts, which predates markets and does not define costs consistent with market economics. Market sellers should not rely solely on the FERC System of Accounts for the calculation of their variable operating and maintenance costs. The FERC System of Accounts does not differentiate between short run marginal costs and avoidable costs. The FERC System of Accounts does not differentiate between costs directly related to energy production and costs not directly related to energy production. Reliance on the FERC System of Accounts for the calculation of variable operating and maintenance costs is likely to lead to incorrect, overstated costs.

The MMU recommends removal of all references to and reliance on 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.[208]

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. On December 2, 2022, PJM filed tariff changes removing labor costs from

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

cost-based offers. The changes were approved by the Commission on January 10, 2023 and became effective on June 1, 2023.[209]

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 unit 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 recommended 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.

In 2022, the MMU and PJM proposed changing the start cost definition of units with a steam process to include the costs from the beginning of the start sequence to dispatchable.[210] The new definition included what is commonly consider soak costs in the start cost. The new definition was combined with the elimination of make whole payments to units with a steam process for MW produced before the unit becomes dispatchable. The proposal was approved by the Commission on January 10, 2023 and became effective on June 1, 2023.[211]

209 *See* Federal Energy Regulatory Commission, Docket No. ER23-557-000 (January 10, 2023) at 1.
210 *See* "Start Cost Alternate Proposal," MMU presentation to the Cost Development Subcommittee. (December 2, 2021) <20211202-item-06-start-cost-alternate-proposal.ashx>.
211 *See* Federal Energy Regulatory Commission, Docket No. ER23-557-000 (January 10, 2023) at 1.

Even though the MMU developed and supported the new definition, it is important to recognize that this approach should be temporary until PJM implements an approach that reflects soak time, soak costs and soak energy output. The main shortcoming of the new definition is that PJM models do not properly value the energy produced during the soak process (soak energy output). Instead, the proposal simply assumes that such MWh are valued at PJM's station service rate. The ideal solution is to model start costs and soak costs separately since there are revenues associated with the MWh produced during soaking, while during the start process there are no MWh being injected into the grid.

The MMU recommends that soak costs, soak time and the MWh produced during soaking be modeled separately. This will ensure that the time required for units to reach a dispatchable level is known and used in the unit commitment process instead of only being communicated verbally between dispatchers and generators. Separating soak costs from start costs and modeling the MWh produced during soaking allows for a better representation of the costs because it eliminates the need to simply assume the price paid for those MWh.

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 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.

Gas Pipeline Penalties

Section 2.2.2 of PJM Manual 15 states that gas pipeline penalties are not includable in cost-based offers. Penalties can be incurred by units for many situations, for example, withdrawing gas not nominated and deviating from an imposed threshold during an operational flow order. Any unit with cost-based offers that include gas pipeline penalties will be subject to penalties per Schedule 2 of the PJM Operating Agreement.

Many Market Sellers rely on independent third party quotes to estimate or determine the gas spot price. The quotes received from these third parties should not be based on incurring gas pipeline penalties. It is recommended that Market Sellers confirm with their third parties that gas is available to them without the need to incur gas pipeline penalties. If that is not possible, the units should be unavailable until the third party can confirm that gas is available without incurring penalties.

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

The 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.[212] One unit qualified for an FMU adder for the months of September and October, 2019. In 2020, five units qualified for an FMU adder in at least one month. In 2021, one unit qualified for an FMU adder in January. In 2022, no units qualified for an FMU adder. In the first nine months of 2023, no units qualified for an FMU adder.

Table 3-126 shows, by month, the number of FMUs and AUs from January 2021 through September 2023. For example, in January 2021, there were zero units that qualified as an FMU or AU in Tier 1, one unit qualified as an FMU or AU in Tier 2, and zero units qualified as an FMU or AU in Tier 3.

Table 3-126 Number of frequently mitigated units and associated units (By month): January 2021 through September 2023

	2021				2022				2023			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	0	1	0	1	0	0	0	0	0	0	0	0
February	0	0	0	0	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0	0	0
June	0	0	0	0	0	0	0	0	0	0	0	0
July	0	0	0	0	0	0	0	0	0	0	0	0
August	0	0	0	0	0	0	0	0	0	0	0	0
September	0	0	0	0	0	0	0	0	0	0	0	0
October	0	0	0	0	0	0	0	0				
November	0	0	0	0	0	0	0	0				
December	0	0	0	0	0	0	0	0				

212 For a definition of FMUs and AUs, and for historical FMU/AU results, see the *2018 State of the Market Report for PJM*, Volume II, Section 3, Energy Market, at Frequently Mitigated Units (FMU) and Associated Units (AU).

For the 2020/2021 through 2022/2023 planning years, default Avoidable Cost Rates were not defined in the tariff. During this period, 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) were greater than zero, and if the generating unit did not have an approved unit specific Avoidable Cost Rate, the generating unit would 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 3-127 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.[213] 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 2023, and summed by the parent company that offers the marginal resource into the real-time energy market. In the first nine months of 2023, the offers of one company resulted in 16.9 percent of the real-time load-weighted PJM system LMP and the offers of the top four companies resulted in 41.1 percent of the real-time load-weighted average PJM system LMP. In the first nine months of 2023, the offers of one company resulted in 17.4 percent of the peak hour real-time load-weighted PJM system LMP.

Table 3-127 Marginal unit contribution to real-time load-weighted LMP (By parent company): January through September, 2022 and 2023

2022 (Jan - Sep)						2023 (Jan - Sep)					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	14.9%	14.9%	1	14.8%	14.8%	1	16.9%	16.9%	1	17.4%	17.4%
2	11.6%	26.5%	2	13.8%	28.6%	2	8.2%	25.0%	2	9.4%	26.8%
3	8.8%	35.3%	3	8.8%	37.4%	3	8.1%	33.2%	3	8.7%	35.6%
4	8.7%	44.0%	4	8.3%	45.6%	4	8.0%	41.1%	4	6.9%	42.5%
5	5.2%	49.2%	5	5.9%	51.6%	5	7.3%	48.4%	5	6.8%	49.3%
6	4.3%	53.5%	6	4.9%	56.5%	6	7.1%	55.5%	6	6.7%	56.1%
7	4.1%	57.7%	7	4.5%	61.0%	7	3.2%	58.6%	7	3.0%	59.1%
8	4.1%	61.7%	8	2.9%	63.9%	8	2.7%	61.3%	8	2.7%	61.9%
9	3.1%	64.8%	9	2.9%	66.8%	9	2.6%	63.9%	9	2.3%	64.2%
Other (89 companies)	35.2%	100.0%	Other (86 companies)	33.2%	100.0%	Other (83 companies)	36.1%	100.0%	Other (79 companies)	35.8%	100.0%

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

Figure 3-67 shows the marginal unit contribution to the real-time load-weighted PJM system LMP summed by parent companies for the first nine months of every year since 2012.

Figure 3-67 Marginal unit contribution to real-time load-weighted LMP (By parent company): January through September, 2013 through 2023

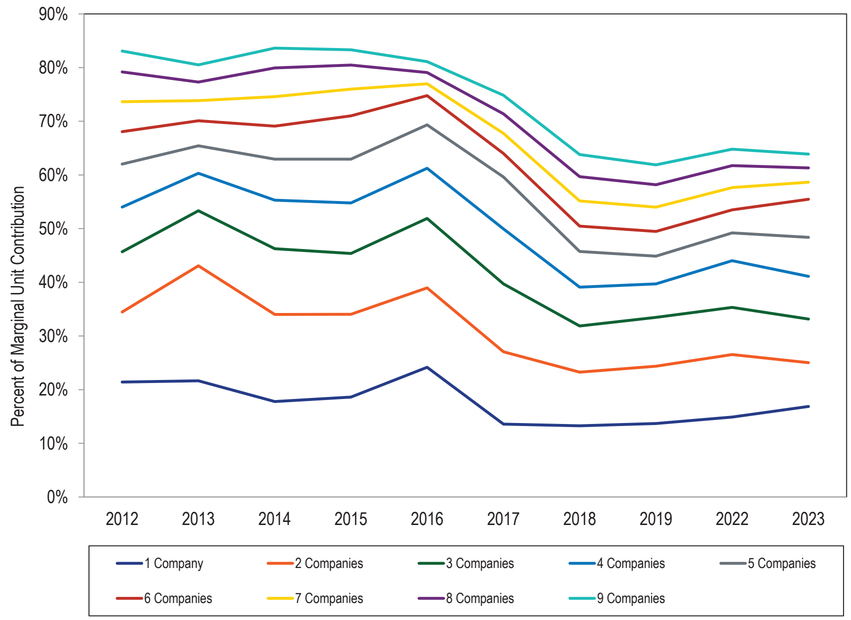


Table 3-128 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[214] The contribution of each marginal resource to price at each load bus is calculated hourly, and summed by the parent company that offers the marginal resource into the day-ahead energy market.

The results show that in the first nine months of 2023, the offers of one company contributed 10.7 percent of the day-ahead load-weighted average PJM system LMP and that the offers of the top four companies contributed 34.1 percent of the day-ahead load-weighted average PJM system LMP.

214 The dispatch run marginal resource and sensitivity factor data is used to calculate the results in the day-ahead market for January 2022 through March 2023 due to the inaccuracy of the sensitivity factor data in the pricing run even though PJM uses LMPs generated in the pricing run as settlement LMPs.

Table 3-128 Marginal resource contribution to day-ahead load-weighted LMP (By parent company): January through September, 2022 and 2023

2022 (Jan - Sep)						2023 (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	8.3%	8.3%	1	9.6%	9.6%	1	10.7%	10.7%	1	10.9%	10.9%
2	8.2%	16.6%	2	7.8%	17.4%	2	10.1%	20.7%	2	8.7%	19.6%
3	6.9%	23.5%	3	7.2%	24.6%	3	7.3%	28.0%	3	7.7%	27.3%
4	5.0%	28.5%	4	5.5%	30.1%	4	6.0%	34.1%	4	5.8%	33.1%
5	4.7%	33.2%	5	4.7%	34.8%	5	5.1%	39.2%	5	5.5%	38.5%
6	4.5%	37.7%	6	4.6%	39.5%	6	4.3%	43.5%	6	3.9%	42.4%
7	4.0%	41.8%	7	4.3%	43.8%	7	3.2%	46.7%	7	3.2%	45.6%
8	3.9%	45.7%	8	3.9%	47.7%	8	2.8%	49.5%	8	3.1%	48.7%
9	3.5%	49.1%	9	3.3%	51.0%	9	2.7%	52.2%	9	2.9%	51.6%
Other (153 companies)	50.9%	100.0%	Other (145 companies)	49.0%	100.0%	Other (145 companies)	47.8%	100.0%	Other (142 companies)	48.4%	100.0%

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.[215] 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.

215 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. *See* Calculation and Use of Generator Sensitivity/Unit Participation Factors, 2010 State of the Market Report for PJM: Technical Reference for PJM Markets.

Real-Time Markup

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

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

PJM implemented fast start pricing on September 1, 2021. Under the fast start pricing rules, the LMPs are calculated in the pricing run, where the offer price of a marginal fast start unit includes amortized commitment costs. For all the fast start marginal units starting from September 1, 2021, the markup includes markup in the incremental offer, markup in the amortized start up offer and markup in the amortized no load offer.

Table 3-129 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 $8.35 per MWh in the first nine months of 2022 to $2.69 per MWh in the first nine months of 2023. The adjusted markup contribution of coal units in the first nine months of 2023 was $0.08 per MWh. The adjusted markup component of gas fired units in the first nine months of 2023 was $2.79 per MWh, a decrease of $2.95 per MWh from the first nine months of 2022. The markup component of wind units was $0.01 per MWh. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In the first nine months of 2023, among the wind units that were marginal, 55.3 percent had negative offer prices.

Table 3-129 Markup component of real-time load-weighted average LMP by primary fuel type and unit type: January through September, 2022 and 2023[216]

		2022 (Jan - Sep)		2023 (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	$1.91	$2.65	($0.44)	$0.08
Gas	CC	$1.73	$4.07	$1.15	$1.98
Gas	CT	$0.01	$1.52	$0.38	$0.82
Gas	RICE	($0.02)	$0.06	($0.01)	$0.01
Gas	Steam	($0.04)	$0.09	($0.09)	($0.02)
Municipal Waste	RICE	($0.00)	($0.00)	$0.02	$0.02
Oil	CC	($0.02)	($0.01)	($0.03)	($0.02)
Oil	CT	($0.06)	$0.01	($0.13)	($0.12)
Oil	RICE	$0.00	$0.00	$0.00	$0.00
Oil	Steam	($0.08)	($0.07)	($0.09)	($0.08)
Other	Solar	$0.01	$0.01	$0.01	$0.01
Other	Steam	$0.00	$0.00	$0.00	$0.00
Wind		$0.02	$0.02	$0.01	$0.01
Total		$3.47	$8.35	$0.77	$2.69

Markup Component of Real-Time Price

Table 3-130 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-131 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 2023, when using unadjusted cost-based offers, $0.77 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-based offers, $2.69 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first nine months of 2023, the peak markup component was highest in July, $3.23 per MWh using unadjusted cost-based offers and peak markup component was highest in July, $5.95 per MWh using adjusted cost-based offers. This corresponds to 6.7 percent of the real-time peak load weighted average LMP in July and 12.4 percent of the real-time peak, load-weighted average LMP in July.

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

Table 3-130 Monthly markup components of real-time load-weighted LMP (Unadjusted): January 2022 through September 2023

	2022			2023		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$2.05	$0.96	$3.04	$0.45	$0.45	$0.44
Feb	$2.32	$2.19	$2.46	($0.82)	($0.39)	($1.25)
Mar	$0.88	$0.43	$1.37	$0.51	$0.66	$0.34
Apr	$4.03	$5.64	$2.42	($0.06)	$0.29	($0.38)
May	$1.93	$3.49	$0.43	$0.61	$1.22	($0.05)
Jun	$5.83	$10.12	$0.47	$0.95	$1.52	$0.30
Jul	$5.65	$8.38	$3.05	$1.70	$3.23	$0.25
Aug	$5.62	$5.33	$5.97	$2.05	$2.35	$1.69
Sep	$2.09	$1.63	$2.57	$0.92	$1.08	$0.76
Oct	$3.89	$4.52	$3.28			
Nov	$0.95	$2.16	($0.25)			
Dec	$3.64	$5.93	$1.61			
Total	$3.32	$4.37	$2.26	$0.77	$1.26	$0.26

Table 3-131 Monthly markup components of real-time load-weighted LMP (Adjusted): January 2022 through September 2023

	2022			2023		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$6.10	$5.08	$7.03	$2.56	$2.70	$2.43
Feb	$5.59	$5.44	$5.74	$0.86	$1.42	$0.30
Mar	$4.03	$3.79	$4.29	$2.32	$2.56	$2.06
Apr	$8.26	$10.30	$6.23	$1.66	$2.25	$1.12
May	$6.60	$8.71	$4.57	$2.33	$3.17	$1.44
Jun	$11.35	$16.57	$4.81	$2.73	$3.49	$1.84
Jul	$11.65	$15.45	$8.03	$4.01	$5.95	$2.17
Aug	$12.48	$13.13	$11.68	$4.13	$4.66	$3.50
Sep	$7.61	$7.86	$7.35	$2.90	$3.37	$2.45
Oct	$7.60	$8.80	$6.44			
Nov	$4.36	$5.77	$2.97			
Dec	$8.69	$10.34	$7.21			
Total	$8.02	$9.54	$6.48	$2.69	$3.40	$1.97

Hourly Markup Component of Real-Time Prices

Figure 3-68 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in the first nine months of 2023 and 2022. Figure 3-69 shows the markup contribution to the hourly load-weighted LMP using adjusted cost-based offers in the first nine months of 2023 and 2022.

Figure 3-68 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): 2022 and January through September, 2023

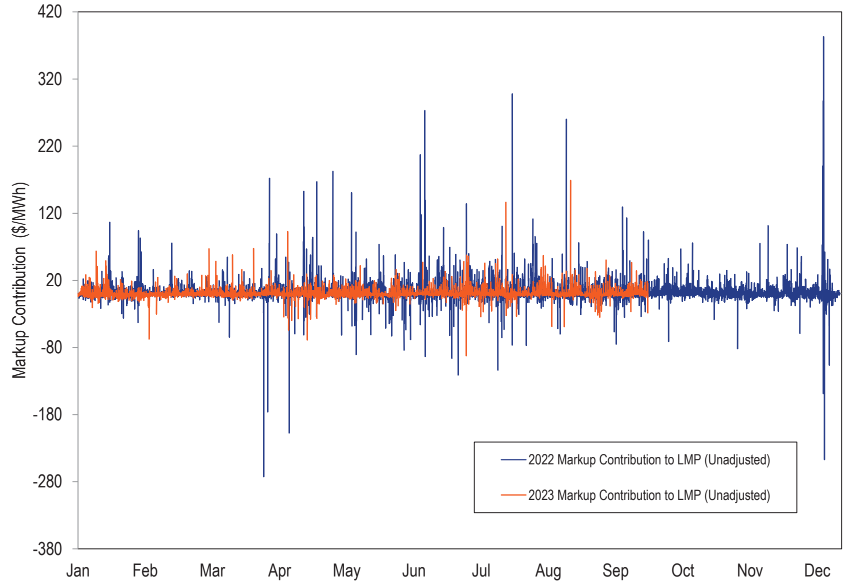
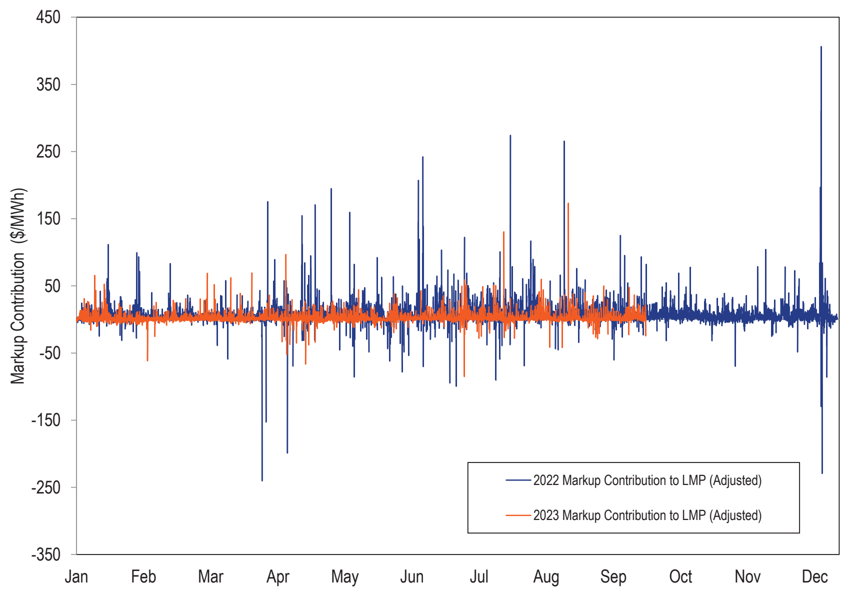


Figure 3-69 Markup contribution to real-time hourly load-weighted LMP (Adjusted): 2022 and January through September, 2023



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 2022 and the first nine months of 2023 in Table 3-132 and for adjusted offers in Table 3-133.[217] The smallest zonal all hours average markup component using unadjusted offers in the first nine months of 2023, was in the DPL Zone, -$0.32 per MWh, while the highest was in the BGE Zone, $1.77 per MWh. The smallest zonal on peak average markup component using unadjusted offers in the first nine months of 2023, was in the DPL Zone, -$0.32 per MWh, while the highest was in the BGE Zone, $2.62 per MWh.

217 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 3-132 Real-time average zonal markup component (Unadjusted): January through September, 2022 and 2023

	2022 (Jan - Sep)			2023 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$1.90	$2.35	$1.42	($0.08)	$0.14	($0.30)
AEP	$3.64	$4.79	$2.44	$0.95	$1.47	$0.41
APS	$3.54	$4.38	$2.67	$0.96	$1.56	$0.35
ATSI	$3.47	$4.63	$2.27	$0.87	$1.42	$0.31
BGE	$5.17	$6.41	$3.87	$1.77	$2.62	$0.89
COMED	$3.10	$4.35	$1.80	$0.61	$1.07	$0.13
DAY	$3.69	$4.91	$2.43	$1.06	$1.53	$0.58
DOM	$4.57	$5.39	$3.71	$1.41	$2.14	$0.66
DPL	$1.72	$2.22	$1.20	($0.32)	($0.32)	($0.31)
DUKE	$3.62	$4.85	$2.35	$1.05	$1.58	$0.50
DUQ	$3.38	$4.44	$2.28	$0.89	$1.45	$0.33
EKPC	$3.70	$4.91	$2.45	$1.05	$1.65	$0.43
JCPLC	$2.08	$2.58	$1.56	($0.11)	$0.06	($0.28)
MEC	$3.35	$3.84	$2.84	($0.04)	$0.34	($0.43)
OVEC	$3.55	$4.55	$2.53	$0.98	$1.50	$0.45
PE	$2.66	$3.47	$1.82	$0.56	$0.99	$0.13
PECO	$1.90	$2.49	$1.29	($0.20)	($0.11)	($0.30)
PEPCO	$4.73	$5.74	$3.69	$1.54	$2.41	$0.65
PPL	$2.63	$3.02	$2.23	($0.16)	$0.04	($0.36)
PSEG	$2.38	$3.04	$1.69	($0.10)	$0.07	($0.27)
REC	$2.24	$2.93	$1.53	$0.06	$0.26	($0.14)

Table 3-133 Real-time average zonal markup component (Adjusted): January through September, 2022 and 2023

	2022 (Jan - Sep)			2023 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$5.79	$6.54	$5.00	$1.36	$1.70	$1.02
AEP	$8.63	$10.47	$6.73	$2.95	$3.71	$2.18
APS	$8.60	$10.09	$7.07	$2.97	$3.79	$2.14
ATSI	$8.28	$10.02	$6.48	$2.84	$3.61	$2.05
BGE	$11.34	$13.49	$9.13	$4.15	$5.26	$3.01
COMED	$7.74	$9.74	$5.66	$2.52	$3.26	$1.77
DAY	$8.82	$10.75	$6.82	$3.14	$3.84	$2.42
DOM	$10.33	$11.97	$8.62	$3.65	$4.65	$2.63
DPL	$5.72	$6.48	$4.93	$1.20	$1.35	$1.04
DUKE	$8.61	$10.52	$6.63	$3.08	$3.84	$2.31
DUQ	$8.11	$9.76	$6.41	$2.83	$3.60	$2.05
EKPC	$8.71	$10.59	$6.76	$3.06	$3.88	$2.22
JCPLC	$6.04	$6.80	$5.26	$1.39	$1.69	$1.08
MEC	$7.98	$8.98	$6.95	$1.63	$2.22	$1.02
OVEC	$8.47	$10.13	$6.75	$2.96	$3.70	$2.21
PE	$7.15	$8.43	$5.83	$2.40	$3.03	$1.76
PECO	$5.65	$6.48	$4.79	$1.17	$1.37	$0.97
PEPCO	$10.64	$12.46	$8.76	$3.79	$4.90	$2.66
PPL	$6.90	$7.64	$6.13	$1.38	$1.76	$0.98
PSEG	$6.35	$7.29	$5.37	$1.42	$1.72	$1.11
REC	$6.34	$7.37	$5.28	$1.69	$2.04	$1.33

Markup by Real-Time Price Levels

Table 3-134 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 3-134 Real-time markup contribution (By load-weighted LMP category, unadjusted): January through September, 2022 and 2023

	2022 (Jan - Sep)		2023 (Jan - Sep)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($5.89)	0.1%	($3.14)	0.9%
$10 to $15	($5.02)	0.1%	($1.24)	7.2%
$15 to $20	($2.27)	0.3%	($1.18)	18.3%
$20 to $25	($1.94)	0.6%	($1.18)	21.4%
$25 to $50	($0.14)	33.4%	$0.58	44.4%
$50 to $75	$1.22	31.7%	$7.68	5.8%
$75 to $100	$3.66	16.6%	$17.36	1.4%
$100 to $125	$6.16	8.4%	$22.68	0.3%
$125 to $150	$10.77	4.2%	$34.70	0.2%
>= $150	$22.15	4.6%	$6.45	0.1%

Table 3-135 Real-time markup contribution (By load-weighted LMP category, adjusted): January through September, 2022 and 2023

	2022 (Jan - Sep)		2023 (Jan - Sep)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($4.75)	0.1%	($2.24)	0.9%
$10 to $15	($3.11)	0.1%	($0.13)	7.2%
$15 to $20	($0.61)	0.3%	$0.18	18.3%
$20 to $25	$0.04	0.6%	$0.45	21.4%
$25 to $50	$3.03	33.4%	$2.76	44.4%
$50 to $75	$5.60	31.7%	$10.52	5.8%
$75 to $100	$9.41	16.6%	$20.05	1.4%
$100 to $125	$13.40	8.4%	$25.07	0.3%
$125 to $150	$18.69	4.2%	$39.52	0.2%
>= $150	$29.45	4.6%	$8.24	0.1%

Markup by Company

Table 3-136 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 2023, when using unadjusted cost-based offers, the markup of one company accounted for 2.9 percent of the load-weighted average LMP, the markup of the top five companies accounted for 4.9 percent of the load-weighted average LMP and the markup of all companies accounted for 2.5 percent of the load-weighted average LMP. The share of top five companies' markup contribution to the load-weighted average LMP increased and the dollar values of their markup decreased in the first nine months of 2023. The markup contribution to the load-weighted average LMP decreased and share of the markup contribution to the load-weighted average LMP decreased in the first nine months of 2023. The markup contribution of a unit to the real-time load-weighted average LMP can be positive or negative.

Table 3-136 Markup component of real-time load-weighted average LMP by Company: January through September, 2022 and 2023

	2022 (Jan - Sep)				2023 (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	$1.08	1.4%	$1.63	2.1%	$0.90	2.9%	$1.09	3.5%
Top 2 Companies	$1.92	2.5%	$2.67	3.4%	$1.10	3.6%	$1.38	4.5%
Top 3 Companies	$2.43	3.1%	$3.56	4.6%	$1.27	4.1%	$1.62	5.3%
Top 4 Companies	$2.73	3.5%	$4.11	5.3%	$1.41	4.6%	$1.82	5.9%
Top 5 Companies	$2.98	3.8%	$4.65	6.0%	$1.51	4.9%	$1.97	6.4%
All Companies	$3.47	4.5%	$8.35	10.7%	$0.77	2.5%	$2.69	8.7%

Day-Ahead Markup[218]

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 3-137. INC, DEC and up to congestion transactions (UTC) have zero markups. UTCs were 52.8 percent of marginal resources, INCs were 14.7 percent of marginal resources and DECs were 18.0 percent of marginal resources in the first nine months of 2023. 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.

218 The dispatch run marginal resource and sensitivity factor data is used to calculate the results in the day-ahead market for January 2022 through March 2023 due to the inaccuracy of the sensitivity factor data in the pricing run even though PJM uses LMPs generated in the pricing run as settlement LMPs.

Table 3-137 shows the markup component of LMP for marginal generating resources. Generating resources were only 13.3 percent of marginal resources in the first nine months of 2023. The adjusted markup component of LMP for coal fired units decreased from $3.11 per MWh in the first nine months of 2022, to $0.13 per MWh in the first nine months of 2023. The adjusted markup component of LMP for gas fired CC units decreased from $2.09 per MWh in the first nine months of 2022, to $0.99 per MWh in the first nine months of 2023.

Table 3-137 Markup component of day-ahead load-weighted average LMP by primary fuel type and technology type: January through September, 2022 and 2023

		2022 (Jan - Sep)		2023 (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	$2.29	$3.11	($0.47)	$0.13
Gas	CC	$1.00	$2.09	$0.67	$0.99
Gas	CT	$0.06	$0.08	$0.03	$0.05
Gas	RICE	($0.00)	$0.00	$0.01	$0.01
Gas	Steam	($0.04)	$0.06	($0.10)	($0.03)
Municipal Waste	RICE	$0.00	$0.00	$0.00	$0.00
Municipal Waste	Steam	($0.00)	($0.00)	$0.00	$0.00
Oil	CC	$0.00	$0.00	($0.00)	($0.00)
Oil	CT	($0.02)	($0.01)	($0.13)	($0.13)
Oil	RICE	($0.00)	($0.00)	$0.00	$0.00
Oil	Steam	($0.00)	$0.00	($0.06)	($0.05)
Other	Solar	$0.48	$0.48	$0.13	$0.13
Other	Steam	$0.00	$0.00	($0.00)	($0.00)
Uranium	Steam	$0.00	$0.00	$0.00	$0.00
Water	Hydro	$0.00	$0.00	$0.01	$0.01
Wind	Wind	$0.47	$0.47	$0.86	$0.86
Total		$4.25	$6.28	$0.95	$1.96

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 3-138 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 2023, when using unadjusted cost-based offers, $0.95 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first nine months of 2023, the peak markup component was highest in July, $7.70 per MWh using unadjusted cost-based offers and the off peak markup component was highest in September, $1.65 per MWh.

Table 3-138 Monthly markup components of day-ahead (Unadjusted) load-weighted LMP: January 2022 through September 2023

	2022			2023		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$2.10	$2.25	$1.96	$1.09	$1.43	$0.77
Feb	$1.73	$1.82	$1.64	($0.16)	$0.31	($0.64)
Mar	$0.85	$0.67	$1.05	$0.33	$0.91	($0.31)
Apr	$1.90	$2.65	$1.17	($1.19)	($2.51)	$0.04
May	$2.08	$2.70	$1.44	$0.34	$0.48	$0.19
Jun	$2.74	$4.16	$0.99	$0.90	$0.91	$0.89
Jul	$3.43	$4.95	$1.96	$4.00	$7.70	$0.42
Aug	$2.52	$3.85	$0.89	$1.01	$1.71	$0.16
Sep	$1.68	$2.25	$1.10	$1.15	$0.63	$1.65
Oct	$1.83	$2.16	$1.51			
Nov	($0.20)	$0.21	($0.60)			
Dec	$5.28	$4.08	$6.35			
Total	$2.20	$2.81	$1.58	$0.95	$1.50	$0.37

Table 3-139 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 2023, when using adjusted cost-based offers, $1.96 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first nine months of 2023, the peak markup component was highest in July, $9.07 per MWh using adjusted cost-based offers and the off peak markup component was highest in September, $2.48 per MWh.

Table 3-139 Monthly markup components of day-ahead (Adjusted) load-weighted LMP: January 2022 through September 2023

	2022			2023		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$3.38	$3.65	$3.12	$2.18	$2.51	$1.87
Feb	$2.66	$2.75	$2.58	$1.01	$1.47	$0.54
Mar	$1.61	$1.44	$1.80	$1.27	$1.86	$0.63
Apr	$2.78	$3.43	$2.15	($0.52)	($1.89)	$0.75
May	$3.04	$3.49	$2.57	$1.00	$1.22	$0.77
Jun	$3.66	$4.93	$2.09	$1.98	$2.14	$1.78
Jul	$4.52	$6.01	$3.08	$5.25	$9.07	$1.55
Aug	$3.74	$4.98	$2.22	$2.34	$2.91	$1.64
Sep	$2.82	$3.36	$2.26	$1.98	$1.45	$2.48
Oct	$2.98	$3.20	$2.76			
Nov	$1.11	$1.68	$0.54			
Dec	$8.01	$6.32	$9.53			
Total	$3.33	$3.87	$2.78	$1.96	$2.54	$1.37

Markup Component of Day-Ahead Zonal Prices

Table 3-140 shows the markup component of annual average day-ahead price using unadjusted cost-based offers for each zone.

The smallest zonal all hours average markup component using unadjusted cost-based offers for the first nine months of 2023 was in PECO, -$0.03 per MWh, while the highest was in COMED, $1.85 per MWh. The smallest zonal on peak average markup using unadjusted cost-based offers was in DOM, -$0.22 per MWh, while the highest was in APS, $3.07 per MWh.

Table 3-140 Day-ahead average zonal markup component (Unadjusted): January through September, 2022 and 2023

	2022 (Jan - Sep)			2023 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$4.51	$6.09	$2.90	$0.52	$1.64	($0.61)
AEP	$4.42	$5.95	$2.83	$1.28	$1.87	$0.67
APS	$4.33	$5.59	$3.03	$1.72	$3.07	$0.34
ATSI	$4.55	$6.05	$2.94	$1.30	$1.89	$0.69
BGE	$4.15	$5.20	$3.06	$0.90	$1.13	$0.66
COMED	$4.61	$6.16	$2.97	$1.85	$2.61	$1.05
DAY	$4.59	$6.10	$2.96	$1.31	$1.45	$1.15
DUKE	$4.68	$6.35	$2.91	$1.50	$1.92	$1.06
DOM	$3.61	$5.09	$2.11	$0.13	($0.22)	$0.48
DPL	$3.45	$4.34	$2.53	$0.74	$1.69	($0.25)
DUQ	$4.52	$6.07	$2.90	$1.11	$1.86	$0.35
EKPC	$4.54	$6.05	$3.03	$1.53	$2.21	$0.85
JCPLC	$4.61	$6.24	$2.84	$0.00	$0.53	($0.58)
MEC	$3.70	$4.87	$2.42	$1.16	$2.42	($0.24)
OVEC	$3.35	$5.46	$1.65	$0.82	$0.97	$0.59
PE	$3.92	$5.08	$2.70	$0.07	$0.87	($0.78)
PECO	$4.39	$5.91	$2.65	($0.03)	$0.16	($0.24)
PEPCO	$4.39	$5.64	$3.02	$0.87	$1.11	$0.62
PPL	$4.03	$5.31	$2.67	$0.93	$2.17	($0.36)
PSEG	$4.32	$5.86	$2.68	$0.01	$0.62	($0.64)
REC	$4.65	$6.13	$2.98	$0.42	$1.36	($0.64)

Table 3-141 shows the markup component of annual average day-ahead price using adjusted cost-based offers for each zone.

The smallest zonal all hours average markup component using adjusted cost-based offers for the first nine months of 2023 was in PE, $0.82 per MWh, while the highest was in APS, $2.79 per MWh. The smallest zonal on peak average markup using adjusted cost-based offers was in DOM, $0.98 per MWh, while the highest was in APS, $4.18 per MWh.

Table 3-141 Day-ahead average zonal markup component (Adjusted): January through September, 2022 and 2023

	2022 (Jan - Sep)			2023 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$6.39	$7.86	$4.90	$1.36	$2.55	$0.17
AEP	$6.46	$7.89	$4.98	$2.32	$2.90	$1.74
APS	$6.45	$7.61	$5.25	$2.79	$4.18	$1.36
ATSI	$6.61	$8.00	$5.13	$2.34	$2.98	$1.67
BGE	$6.49	$7.39	$5.56	$2.06	$2.32	$1.79
COMED	$6.55	$8.11	$4.90	$2.77	$3.48	$2.02
DAY	$6.73	$8.14	$5.20	$2.40	$2.55	$2.24
DUKE	$6.78	$8.36	$5.11	$2.55	$2.93	$2.14
DOM	$5.76	$7.11	$4.39	$1.29	$0.98	$1.60
DPL	$5.07	$5.82	$4.31	$1.68	$2.76	$0.56
DUQ	$6.53	$7.94	$5.05	$2.26	$3.19	$1.31
EKPC	$6.60	$8.03	$5.17	$2.56	$3.20	$1.91
JCPLC	$6.52	$8.10	$4.80	$0.82	$1.34	$0.26
MEC	$5.69	$6.77	$4.51	$2.26	$3.61	$0.76
OVEC	$5.58	$7.76	$3.82	$1.66	$1.78	$1.47
PE	$5.72	$6.75	$4.64	$0.82	$1.64	($0.05)
PECO	$6.34	$7.75	$4.73	$1.15	$1.53	$0.72
PEPCO	$6.71	$7.84	$5.47	$1.97	$2.17	$1.75
PPL	$5.95	$7.12	$4.71	$1.93	$3.22	$0.57
PSEG	$6.21	$7.62	$4.71	$0.82	$1.40	$0.21
REC	$6.48	$7.77	$5.03	$1.30	$2.20	$0.29

Markup by Day-Ahead Price Levels

Table 3-142 and Table 3-143 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 3-142 Day-ahead average markup component (By LMP category, unadjusted): January through September, 2022 and 2023

	2022 (Jan - Sep)		2023 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $10	$0.00	0.0%	$0.00	0.2%
$10 to $15	$0.00	0.0%	($0.01)	4.5%
$15 to $20	($0.00)	0.1%	$0.04	14.0%
$20 to $25	$0.00	0.2%	($0.02)	20.2%
$25 to $50	$0.33	28.4%	$0.28	56.2%
$50 to $75	$0.83	37.4%	$0.31	3.8%
$75 to $100	$0.86	17.4%	$0.09	0.8%
$100 to $125	$0.94	9.5%	$0.02	0.1%
$125 to $150	$0.47	3.5%	($0.00)	0.1%
>= $150	$0.82	3.4%	$0.24	0.3%

Table 3-143 Day-ahead average markup component (By LMP category, adjusted): January through September, 2022 and 2023

	2022 (Jan - Sep)		2023 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $10	$0.00	0.0%	$0.00	0.2%
$10 to $15	$0.00	0.0%	$0.01	4.5%
$15 to $20	$0.00	0.1%	$0.13	14.0%
$20 to $25	$0.00	0.2%	$0.14	20.2%
$25 to $50	$0.82	28.4%	$0.96	56.2%
$50 to $75	$1.59	37.4%	$0.36	3.8%
$75 to $100	$1.28	17.4%	$0.11	0.8%
$100 to $125	$1.17	9.5%	$0.02	0.1%
$125 to $150	$0.55	3.5%	$0.00	0.1%
>= $150	$0.86	3.4%	$0.24	0.3%

Market Structure, Participant Behavior, and Market Performance

The goal of regulation through competition is to achieve competitive market outcomes even in the presence of market power. Market structure in the PJM energy market is not competitive in local markets created by transmission constraints. At times, market structure is not competitive in the aggregate energy market. Market sellers pursuing their financial interests may choose behavior that benefits from structural market power in the absence of an effective market power mitigation program. The overall competitive assessment evaluates the extent to which participant behavior results in competitive or above competitive pricing. The competitive assessment brings together the structural measures of market power, HHI and pivotal suppliers, with participant behavior, specifically markup, and pricing outcomes.

HHI and Markup

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:[219]

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

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. As HHI decreases, 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 can reach 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 connects market structure (HHI and demand elasticity) to market performance (markup).

The PJM energy market HHIs and application of the FERC concentration categories understate the degree of market power because, in the absence of aggregate market power mitigation, even the unconcentrated HHI level implies 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.[220] Using the Lerner Index, the elasticity of -0.2 implies, for example, an average markup ranging from 25 to 50 percent at the low end of the moderately concentrated threshold HHI of 1000:[221]

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

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 $30.11 per MWh and an average HHI of 682 in the first nine months of 2023, average PJM prices would theoretically range from $36 to $46 per MWh, an implied markup of 17.1 to 34.1 percent, using the elasticity range of -0.2 to -0.4.[222] Given the elasticity estimates, 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 $30.87 per MWh with markups at 8.8 percent, are lower than the theoretical range, supporting the MMU's competitive assessment of the market. However, markup is not zero. In some market intervals, markup and prices reach levels that reflect the exercise of market power.

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

220 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>.

221 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.

222 The average HHI is found in Table 3-91. Marginal costs are the sum of all components of LMP except markup, as shown in Table 3-72.

Market Power Mitigation and Markup

Fully effective market power mitigation would not allow a seller that fails the structural market power test (the TPS test) to set prices with a positive markup. With the flaws in PJM's implementation of the TPS test, resources can and do set prices with a positive markup while failing the TPS test.

Table 3-144 categorizes day-ahead and real-time marginal unit intervals by markup level and TPS test status. In the first nine months of 2023, 4.2 percent of real-time marginal unit intervals and 4.7 percent of day-ahead marginal unit hours included a positive markup even though the resource failed the TPS test for local market power. Unmitigated local market power affects PJM market prices. Zero markup with a TPS test failure indicates the mitigation of a marginal unit.

Table 3-144 Percent of real-time marginal unit intervals with markup and local market power: January through September, 2023

	Day-ahead Market			Real-time Market		
Markup Category	Not Failing TPS Test	Failing TPS Test	Percent in Category	Not Failing TPS Test	Failing TPS Test	Percent in Category
Negative Markup	29.6%	6.4%	36.0%	39.1%	7.3%	46.4%
Zero Markup	17.0%	7.4%	24.4%	13.3%	6.8%	20.1%
$0 to $5	16.6%	1.8%	18.4%	22.0%	2.7%	24.8%
$5 to $10	9.3%	1.2%	10.4%	3.9%	0.5%	4.4%
$10 to $15	3.3%	0.9%	4.3%	1.4%	0.4%	1.9%
$15 to $20	1.9%	0.4%	2.4%	0.6%	0.1%	0.7%
$20 to $25	1.0%	0.3%	1.2%	0.4%	0.1%	0.5%
$25 to $50	1.6%	0.1%	1.7%	0.6%	0.2%	0.8%
$50 to $75	0.8%	0.0%	0.8%	0.2%	0.0%	0.2%
$75 to $100	0.2%	0.0%	0.2%	0.1%	0.0%	0.1%
Above $100	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%
Total Positive Markup	34.7%	4.7%	39.4%	29.3%	4.2%	33.5%
Total	81.3%	18.5%	99.8%	81.7%	18.3%	100.0%

The markup of marginal units was zero or negative in 66.5 percent of real-time marginal unit intervals and 60.4 percent of day-ahead marginal unit intervals in the first nine months of 2023. Zero and negative markup are the expected results in a competitive market. Pivotal suppliers in the aggregate market also set prices with high markups in the first nine months of 2023.

The 34.7 percent of day-ahead marginal units and 29.3 percent of real-time marginal units setting price with a markup without failing the TPS test could represent units with aggregate market power or units that maintain markup in their offer for times when they have local market power. Allowing positive markups to affect prices in the presence of market power permits the exercise of market power and has a negative impact on the competitiveness of the PJM energy market. This problem can and should be addressed.