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 2025.

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 94.1 percent of the days in the first nine months of 2025. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM aggregate energy market in the first nine months of 2025 was, on average, unconcentrated by FERC HHI standards. The average HHI was 686 with a minimum of 511 and a maximum of 988. 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 price formation, undermine market efficiency in the energy market. 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, but, so far, PJM and FERC have failed to address them.[4] [5] [6] 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).
5 185 FERC ¶ 61,158 (2023).
6 189 FERC ¶ 61,060 (2024).

Overview

Supply and Demand

Market Structure

- **Supply.** In the first nine months of 2025, 2,756 MW of new resources were added in the energy market, and 982 MW of resources were retired.
- The real-time hourly on peak average offered supply in the first nine months of 2025 increased by 1.4 percent, from the first nine months of 2024, from 140,934 MWh to 142,851 MWh.
- The day-ahead hourly average offered supply in the first nine months of 2025 decreased by 1.5 percent, from the first nine months of 2024, from 153,603 MWh to 151,275 MWh.
- The real-time hourly average cleared generation in the first nine months of 2025 increased by 3.3 percent from the first nine months of 2024, from 96,954 MWh to 100,136 MWh.
- The day-ahead hourly average cleared supply in the first nine months of 2025, including INCs and UTCs, increased by 1.9 percent from the first nine months of 2024 from 112,192 MWh to 114,328 MWh.
- **Demand.** The real-time hourly peak load without exports in the first nine months of 2025 was 156,256 MWh (158,789 MWh with net exports) in the HE 1800 (EPT) on June 23, 2025, higher than the PJM peak load in the first nine months of 2024, which was 144,245 MWh (149,398 MWh with net exports) in the HE 1800 (EPT) on June 21, 2024.
- The real-time hourly average load in the first nine months of 2025 increased by 3.0 percent from the first nine months of 2024, from 90,917 MWh to 93,683 MWh.
- The day-ahead hourly average cleared demand in the first nine months of 2025, including DECs and UTCs, increased by 1.4 percent from the first nine months of 2024, from 106,355 MWh to 107,864 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 4.6 percent and the cleared increment MW increased by 8.4 percent in the first nine months of 2025 compared to the first nine months of 2024. The hourly average submitted decrement bid MW increased by 17.7 percent and the cleared decrement MW decreased by 2.6 percent in the first nine months of 2025 compared to the first nine months of 2024. The hourly average submitted up to congestion bid MW decreased by 2.1 percent and the cleared up to congestion bid MW decreased by 8.2 percent in the first nine months of 2025 compared to the first nine months of 2024.

Market Performance

- **Generation Fuel Mix.** In the first nine months of 2025, generation from coal units increased 16.1 percent, generation from natural gas units decreased 1.6 percent, generation from oil units increased 25.8 percent, generation from wind units increased 1.8 percent, and generation from solar units increased 46.4 percent compared to the first nine months of 2024.
- **Fuel Diversity.** The fuel diversity of energy generation in the first nine months of 2025, measured by the fuel diversity index for energy (FDI_e), increased 2.5 percent compared to the first nine months of 2024.
- **Marginal Resources.** In the PJM Real-Time Energy Market in the first nine months of 2025, coal units were 7.6 percent, natural gas units were 77.9 percent and wind units were 10.3 percent of marginal resources. In the first nine months of 2024, coal units were 11.0 percent, natural gas units were 74.8 and wind units were 11.9 percent of marginal resources.
- **Prices.** The real-time load-weighted average LMP in the first nine months of 2025 increased $16.20 per MWh, or 47.2 percent from the first nine months of 2024, from $34.31 per MWh to $50.51 per MWh.

- The day-ahead load-weighted average LMP for the first nine months of 2025 increased $16.03 or 47.4 percent from the first nine months of 2024, from $33.85 per MWh to $49.88 per MWh.
- **Fast Start Pricing.** The real-time load-weighted average PLMP was $50.51 per MWh for the first nine months of 2025, which is 9.0 percent, $4.17 per MWh, higher than the real-time load-weighted average DLMP of $46.34 per MWh.
- **Components of Real-Time LMP.** In the PJM Real-Time Energy Market in the first nine months of 2025, 7.2 percent of the real-time load-weighted LMP was the result of coal costs, 43.4 percent was the result of gas costs, 4.3 percent was the result of the cost of emission allowances, and 10.5 percent was the result of transmission constraint violation penalty factors.
- **Components of Day-Ahead LMP.** In the PJM Day-Ahead Energy Market in the six months between April and September of 2025, 7.2 percent of the day-ahead load-weighted LMP was the result of coal costs, 12.2 percent was the result of gas costs, 33.2 percent was the result of the decrement bids, and 18.5 percent was the result of increment offers.
- **Changes in Real-Time LMP.** Of the $16.20 per MWh increase in the real-time load-weighted average LMP, $9.85 per MWh (60.8 percent) was the fuel and consumables cost components of LMP, -$0.16 per MWh (-1.0 percent) was the emissions cost components of LMP, $0.85 per MWh (5.2 percent) was the sum of the markup, maintenance, and ten percent adder components of LMP, $2.07 per MWh (12.8 percent) was the transmission constraint penalty factor component of LMP, and $1.14 per MWh (7.0 percent) was the scarcity component of LMP. The pre-emergency demand response called on by PJM during the hot weather days in June and July increased the LMP by $0.89 per MWh, 5.5 percent of the increase in LMP. The LMP increase would have been higher if PJM had not imposed a $3,700.00 per MWh administrative cap. The administrative cap reduced the LMP by $0.11 per MWh, a 0.7 percent decrease.
- **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 average difference between day-ahead and real-time average prices was $0.38 per MWh in the first nine months of 2025, and $0.41 per MWh in the first nine months of 2024. 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

- **Shortage Intervals.** There were 130 intervals with five minute shortage pricing on 22 days in the first nine months of 2025. Of the 130 intervals, 79 occurred during the June 2025 heatwave, for which PJM issued several emergency warnings and actions. Seven of the 130 intervals of shortage overlapped with synchronized reserve events.
- **SCED Shortage Intervals.** In the first nine months of 2025, there were 4,082 five minute intervals, or 5.2 percent of all five minute intervals, for which at least one RT SCED solution showed a shortage of reserves. In the first nine months of 2025, there were 1,368 five minute intervals, or 1.7 percent of all five minute intervals, for which more than one RT SCED solution showed a shortage of reserves. In the first nine months of 2025, PJM triggered shortage pricing for 130 five minute intervals, or 0.2 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 257 days, 94.1 percent of the days, in the first nine months of 2025 and 138 days, 50.4 percent of the days, in the first nine months of 2024.
- **Local Market Power.** In the first nine months of 2025, in the real-time market, the 500 kV system, 13 zones, and the PJM/MISO interface 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 2025, 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 decreased from 2.0 percent in the first nine months of 2024 to 1.9 percent in the first nine months of 2025. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.5 percent in the first nine months of 2024 to 1.4 percent in the first nine months of 2025. 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 decreased from 0.18 percent in the first nine months of 2024 to 0.10 percent in the first nine months of 2025. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.23 percent in the first nine months of 2024 to 0.12 percent in the first nine months of 2025. The low offer cap percentages for reliability commitments, relative to offer capping for transmission constraints, do not mean that units committed for reliability reasons do not have market power. All units manually committed for reliability have market power and all are treated consistent with that fact.

- **Parameter Mitigation.** PJM applies operating parameter limits (PLS) to units that fail the TPS test and to all units during hot and cold weather alerts. In the first nine months of 2025, 29.3 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, 31.2 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 2025, no units qualified for an FMU adder. In 2024, 2023 and 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 -$0.07 when using unadjusted cost-based offers in the first nine months of 2025, 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 2025 was more than $900 per MWh and the highest markup in the first nine months of 2024 was more than $900 per MWh, using unadjusted cost-based offers.

- While the average markup index in the day-ahead market was $0.23 per MWh in the six months between April and September of 2025, some marginal units did have substantial markups. The highest markup for any marginal unit in the day-ahead market in the six months between April and September of 2025 was more than $550 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 frequency distributions also show that a significant proportion 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 2025, the unadjusted markup component (net of positive and negative markup components) of LMP was -$0.09 per MWh or -0.2 percent of the PJM load-weighted average LMP. July had the highest unadjusted peak markup component, $2.74 per MWh, or 3.5 percent of the real-time peak hour load-weighted average LMP for July.

  In the PJM Day-Ahead Energy Market in the six months between April and September of 2025, the unadjusted markup component (net of positive and negative markup components) of LMP was $2.64 per MWh or 12.2 percent of the PJM load-weighted average LMP. July had the highest unadjusted peak markup component, $7.59 per MWh, or 8.59 percent of the day-ahead peak hour load-weighted average LMP for July.

  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 3.0 percent of all real-time marginal unit intervals in the first nine months of 2025, 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 2025, 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 117 days, compared to 76 days in the first nine months of 2024.[7] Some of the marginal units had local market power, but were not offer capped due to issues with the method that PJM uses to select offer schedules for units that fail the TPS test. Some of the marginal units had aggregate market power, for which there is no offer capping, and some had both local and aggregate market power.

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 per the PJM Operating Agreement 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

7 The number of days reported in the 2025 Quarterly State of the Market Report for PJM: January through March and the 2025 Quarterly State of the Market Report for PJM: January through June were understated, and have been correctly calculated in this 2025 Quarterly State of the Market Report for PJM: January through September.

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 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 maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- 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: Partially adopted 2023.)
- 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 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 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

8 The real-time market formula for determining the lowest cost schedule is documented. The day-ahead market formula for determining the lowest cost schedule is not documented.

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 2021. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation, PJM always use cost-based offers for units that fail the TPS test, and always use flexible parameters for all cost-based and all price-based offers 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, in order to ensure effective market power mitigation, that PJM commit all resources that fail the TPS test on their cost-based offers, that the Market Seller designate the cost-based offer if there is more than one, and that PJM implement this solution as soon as possible. (Priority: High. First reported Q3 2024. 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 an outage that reflects the derate. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that storage resources be subject to an enforceable ICAP must offer rule in the day-ahead and real-time energy markets 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, that gas generators be required to inform PJM about whether they have gas, 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 2022. Status: Not adopted.)

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.

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 supply arrangements at least annually or when such arrangements change, and analyze the associated locational and regional risks to reliability. (Priority: Medium. First reported 2022. 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 manual and automated discretionary reductions in the control limits on transmission constraint line ratings used in the market clearing software (SCED) 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.)

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.

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

- 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 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 LPC and instead limit the sum of violated reserve constraint shadow prices that are included in the determination of LMP in LPC to $1,700 per MWh. While PJM no longer caps prices in RT SCED, PJM continues to apply a cap to the system marginal price in the pricing run (LPC) under fast start pricing. (Priority: Medium. First reported 2021. Status: Not adopted.)

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 2: 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 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.)

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.

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first nine months of 2025, 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 2025, LMP increased by $16.20 per MWh compared to the first nine months of 2024. The fuel cost components of LMP (the sum of gas, coal, oil, landfill gas, and consumables) increased $9.85 per MWh, 60.8 percent of the increase in LMP. The emissions cost components of LMP, including opportunity costs for emissions limited resources, decreased by $0.16 per MWh, -1.0 percent of the increase in LMP. The transmission constraint penalty factor component increased by $2.07 per MWh, 12.8 percent of the increase in LMP, primarily as a result of PJM actions to reduce the line limits applied in SCED (control limits) below the actual line limits. The pre-emergency demand response called on by PJM during the hot weather days in June and July increased the LMP by $0.89 per MWh, 5.5 percent of the increase in LMP. The LMP increase would have been higher if PJM had not imposed a $3,700.00 per MWh administrative cap. The administrative cap reduced the LMP by $0.11 per MWh, a 0.7 percent decrease.

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 2025 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 2025, the sum of the markup, ten percent adder, and maintenance cost (not short run marginal cost) components increased by $0.85 per MWh or 5.2 percent of the increase in LMP. In addition, PJM actions in the form of transmission constraint penalty factors, significantly increased prices.

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, PJM approved 21.9 percent of solved shortage cases in June 2025, but only 3.2 percent for the first nine months of 2025. Six of the other eight months had a higher percent of shortage cases solved, but fewer approved. The pattern of shortage case approvals indicates that PJM considers factors that are not documented in the tariff when deciding whether to approve shortage cases. The application of shortage pricing should not involve operator discretion. As directed by FERC Order No. 825, PJM should approve shortage cases based on market software results alone.[18]

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 to ensure no scarcity pricing when such pricing is not consistent with market conditions. Scarcity pricing for revenue adequacy, as in PJM's 2019 ORDC proposal that would have created administrative scarcity pricing, is not consistent with a competitive market design. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is consistent with a competitive market design. Scarcity pricing is 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.

PJM defined inputs to the dispatch tools, particularly RT SCED, have substantial effects on energy market outcomes. Transmission line ratings in SCED, transmission constraint penalty factors, load forecast bias, hydro resource schedules, fast start pricing, and the treatment of demand resources change the dispatch of the system, affect prices, and can create significant price increases, particularly through transmission constraint penalty factors. PJM operator interventions to reduce the control limits on transmission constraint line ratings in RT SCED unnecessarily trigger transmission constraint penalty factors and significantly increase prices. In the first nine months of 2025, the control limit used in RT SCED for 85 percent of violated transmission constraint intervals was less than 100 percent of the actual line limit, with an average reduction of 5.1 percent. If the control limits had not been artificially reduced for PJM transmission constraints and everything else remained unchanged, the transmission constraint penalty factor's contribution to the load weighted average LMP in the first nine months of 2025 would have decreased by 99.4 percent from $5.31 to $0.03 per MWh. PJM should evaluate its interventions in the market, including the unnecessary imposition of transmission constraint penalty factors, reconsider 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 despite the stated goal of reducing overall uplift, created a greater reliance on uplift rather than price as an incentive to follow PJM's instructions. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs using fast start pricing prioritizes minimizing uplift over minimizing production costs.[19] 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

17 177 FERC ¶ 61,209 (2021).
18 155 FERC ¶ 61,276 at P 161 (2016) ("shortage pricing is required only when a shortage of energy or operating reserves is indicated by the RTO's/ISO's software").
19 See 173 FERC ¶ 61,244 (2020).

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 uplift in an attempt to counter the distorted incentives inherent in fast start pricing. PJM is also using the pricing run to implement administrative pricing rules that are not related to fast start pricing. Specifically, PJM uses lower transmission constraint penalty factors in the day-ahead pricing run than in the dispatch run and implements system marginal price capping in the pricing run. Every difference between the dispatch run and the pricing run introduces another inefficiency in the market. In the four years since fast start pricing was introduced, the market has not responded with new entry of fast start units despite consistently higher LMPs when a fast start unit sets price.

The energy market requires more flexible operation of the dispatchable fleet as wind and solar resource penetration grows. Since 2018, PJM has argued that the way to incent investment in flexible units is to increase reserve requirements and to increase the administrative prices defined in the ORDCs. In fact, PJM's ORDCs would benefit inflexible units. Providing windfall gains to all generation through higher LMPs during more frequent reserve shortages is not an effective incentive for flexibility.

The question of how to provide market incentives for investment in flexibility, and for operating to the full capability of that flexibility 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?

A direct solution would include improved modelling of generator capabilities, so that PJM can send more targeted dispatch signals that generators are consistently capable of following. A direct solution would include targeted reforms to PJM software, like multi-interval dispatch and combined cycle modelling would directly address PJM energy market performance. A direct solution would include stronger standards in the PJM Market Rules for performance of resources to their actual physical parameters. These reforms would be more efficient and effective than simply raising prices across the board.

The relationship between supply and demand 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 at all times. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or the supply from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market with increasing frequency. 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.[20] However, there are 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 recognized some of these issues in its order issued on June 17, 2021, but failed to address them in its November 30, 2023 order.[21] [22] Many of these issues can be resolved by simple rule changes. PJM filed and, on October 25, 2024, FERC accepted a proposal that would require that sellers that fail the TPS test will be

20 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.
21 See 175 FERC ¶ 61,231 (2021).
22 185 FERC ¶ 61,158 (2023).

offer capped at their cost-based offers and that operating parameters will be mitigated.[23] That order has no current effect because FERC approved the PJM filing that linked, for no logical reason, implementing the improved rules to PJM's adoption of an improved combined cycle model with no defined date. The flawed rules remain in place. There is no reason to delay implementation of the FERC approved rules until PJM addresses combined cycle modelling. The changes would decrease the solution time for the day-ahead market and enhance market efficiency. The approved approach should be implemented as soon as possible to help ensure effective market power mitigation.

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 in cost-based energy offers 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 power market will result in higher prices when fuel costs increase and lower prices when fuel costs decrease. A competitive market will not result in higher prices when markups increase based on market power, or when PJM selects a price-based offer including a markup rather than a cost-based offer in the presence of local market power, 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 2025 or prior years. Given the structure of the energy market which can permit the exercise of aggregate and local market power, some participants' offer 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. In addition, PJM's extensive administrative interventions in the energy market should be reduced. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2025.

23 189 FERC ¶ 61,060 (2024).

Supply and Demand

Market Structure

Supply

Supply includes physical generation, imports and virtual transactions.

In the first nine months of 2025, 2,756 MW of new resources were added in the energy market, and 982 MW of resources were retired.

Figure 3-1 shows real-time and day-ahead hourly supply curves for the first nine months of 2024 and 2025.[24] 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 in the first nine months of 2025 increased by 1.4 percent, from the first nine months of 2024, from 140,934 MWh to 142,851 MWh. The day-ahead hourly average offered supply in the first nine months of 2025 decreased by 1.5 percent, from the first nine months of 2024, from 153,603 MWh to 151,275 MWh.

24 Real-time supply includes real-time generation offers and import MWh.

Figure 3-1 Real-time and day-ahead hourly supply curves: January through September, 2024 and 2025

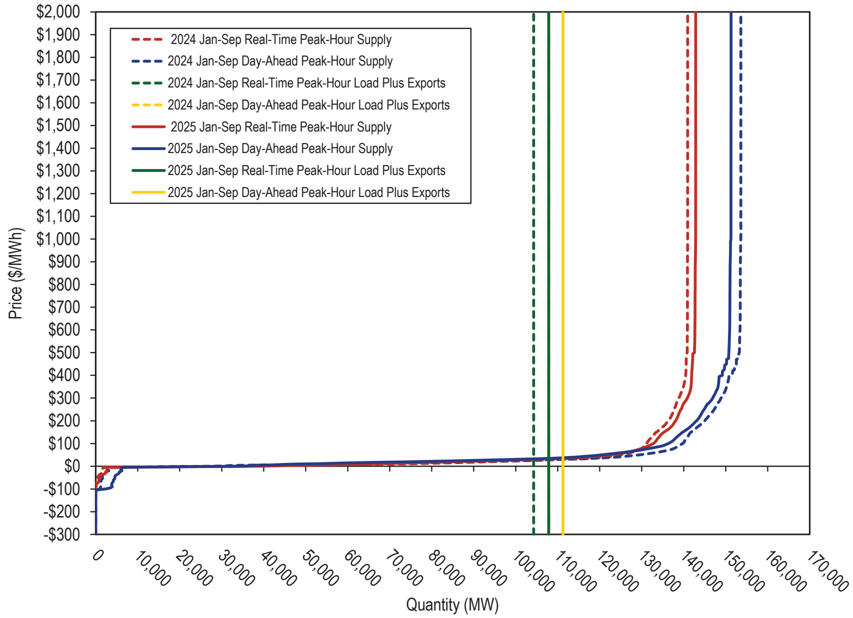


Figure 3-2 shows the typical dispatch range.

Figure 3-2 Typical dispatch range of supply curves

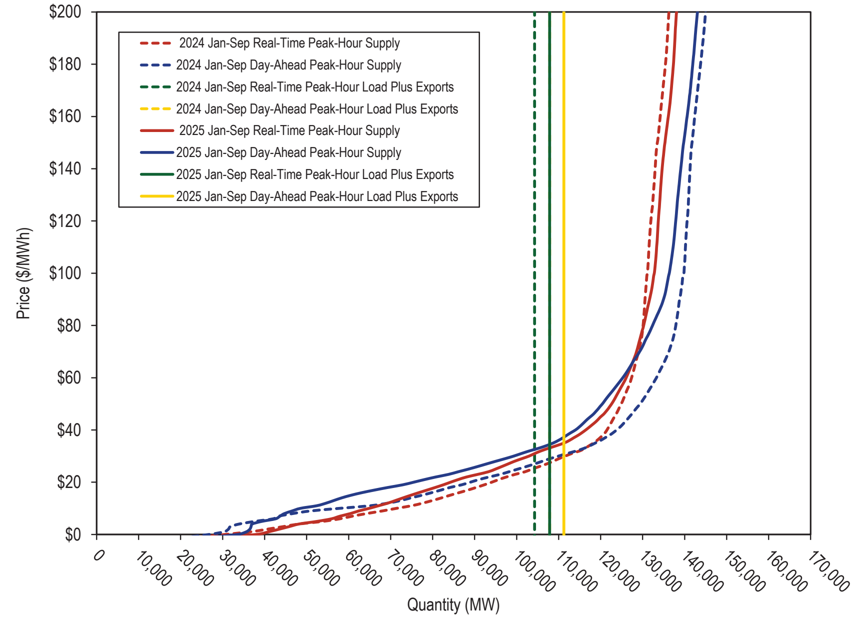


Table 3-2 shows the price elasticity of the real-time supply curve for the peak hours for the first nine months of 2024 and 2025 by load level.[25]

The supply curve in the first nine months of 2025 was most elastic in the 95 to 115 GW range at 0.428, which was more elastic than the supply curve in the 95 to 115 GW range in the first nine months of 2024, with an elasticity of 0.378.

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

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

25 The price elasticity results have been corrected from previous reports.

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 supply curve is inelastic throughout.

Table 3-2 Price elasticity of the supply curve

	GW				
Jan-Sep	Min - 75	75 - 95	95 - 115	115 - 135	135 - Max
2020	0.138	0.643	0.686	0.039	0.004
2021	0.089	0.657	0.502	0.050	0.007
2022	0.046	0.556	0.384	0.102	0.012
2023	0.096	0.361	0.428	0.020	0.005
2024	0.108	0.316	0.378	0.032	0.008
2025	0.061	0.428	0.387	0.053	0.009

Real-Time Supply

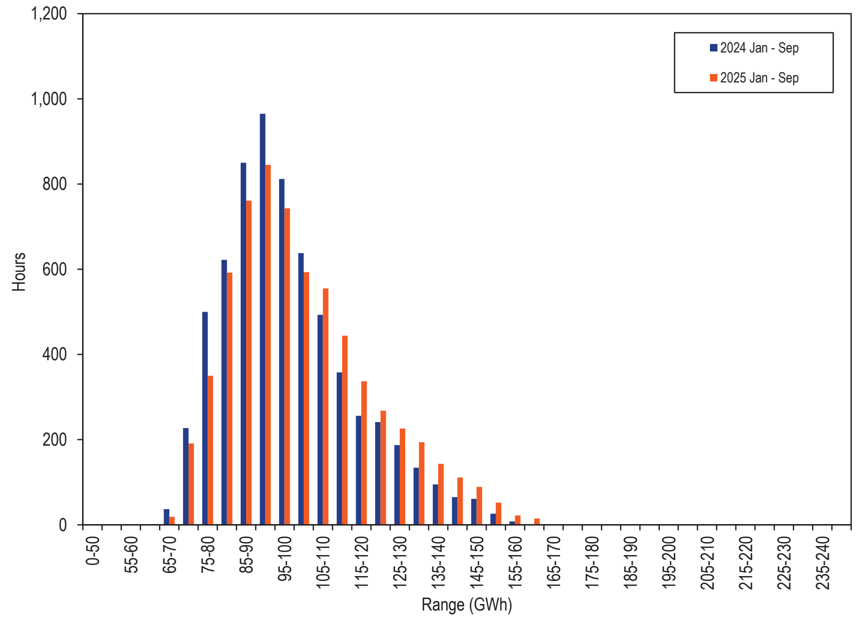
In the PJM Real-Time Energy Market, there are three types of supply offers:[26]

- **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 unit.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. A real-time import must have a valid OASIS reservation when offered, must have available ramp room to support the import, must be accompanied by a NERC Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Supply Duration

Figure 3-3 shows the hourly distribution of the real-time generation plus imports for the first nine months of 2024 and 2025.

Figure 3-3 Distribution of real-time generation plus imports: January through September, 2024 and 2025[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 2025.

The real-time hourly average cleared generation in the first nine months of 2025 increased by 3.3 percent from the first nine months of 2024, from 96,954 MWh to 100,136 MWh.

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

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

The real-time hourly average cleared supply including imports in the first nine months of 2025 increased by 3.5 percent from the first nine months of 2024, from 98,593 MWh to 102,018 MWh.

The real-time hour average cleared generation in the first nine months of 2025 was the highest since the start of PJM markets for the first nine months of a year at 100,136 MWh.

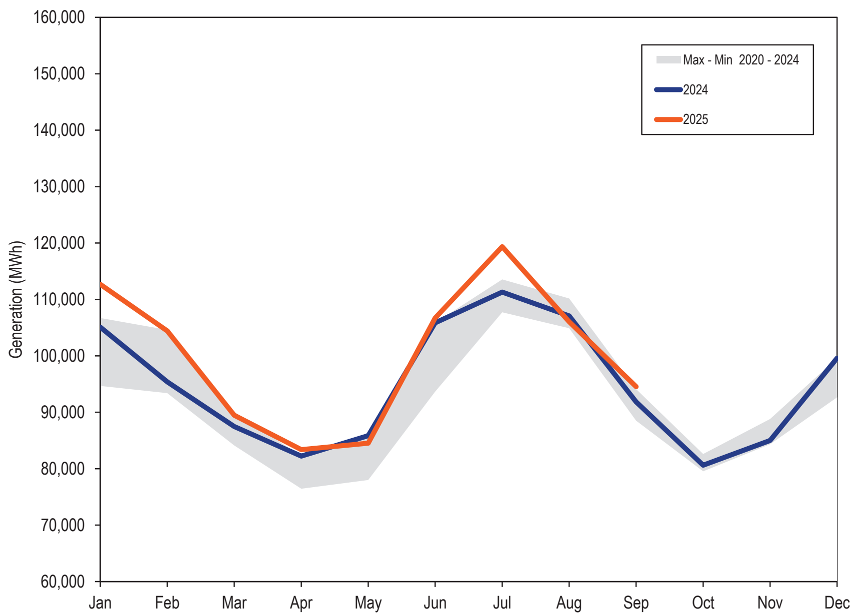
Table 3-3 Real-time hourly average generation and generation plus imports: January through September, 2001 through 2025

	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%)
2024	96,954	16,635	98,593	16,917	3.3%	7.0%	3.3%	8.7%
2025	100,136	18,290	102,018	18,551	3.3%	10.0%	3.5%	9.7%

PJM Real-Time Monthly Average Cleared Supply

Figure 3-4 compares the real-time monthly average generation in 2024 and the first nine months of 2025 with the historic five year range. The real-time monthly average generation in January, April, June, and September 2025 was higher than the maximum monthly average generation for the past five years.

Figure 3-4 Real-time monthly average generation: 2024 through September 2025



Day-Ahead Supply

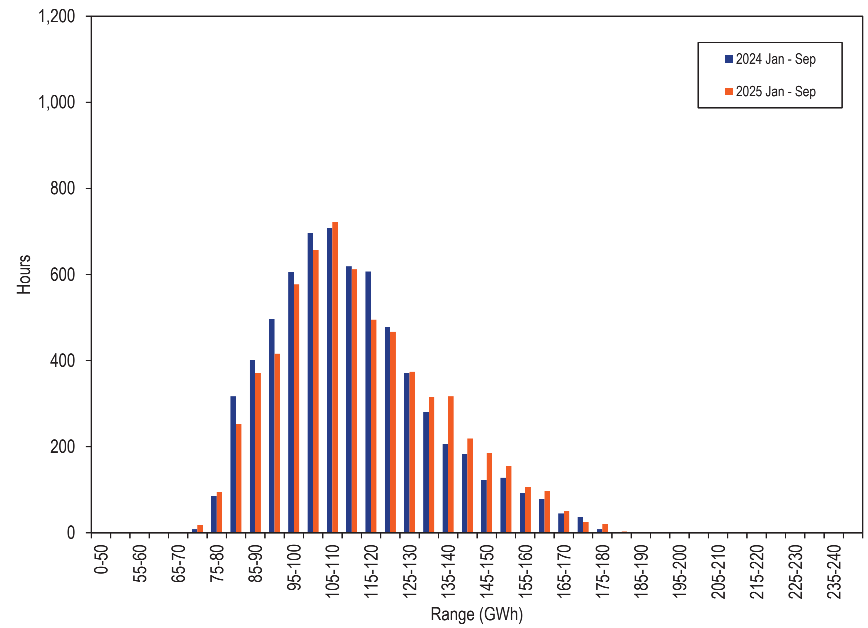
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **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 2024 and 2025.

Figure 3-5 Distribution of day-ahead cleared supply plus imports: January through September, 2024 and 2025[28]



PJM Day-Ahead Average Cleared Supply

Table 3-4 presents day-ahead hourly cleared supply summary statistics for each year for the first nine months of 2001 through 2025.

The day-ahead hourly average cleared supply in the first nine months of 2025, including INCs and UTCs, increased by 1.9 percent from the first nine months of 2024 from 112,192 MWh to 114,328 MWh.

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

The day-ahead hourly average cleared supply in the first nine months of 2025, including INCs, UTCs and imports, increased by 1.9 percent from the first nine months of 2024, from 112,477 MWh to 114,585 MWh.

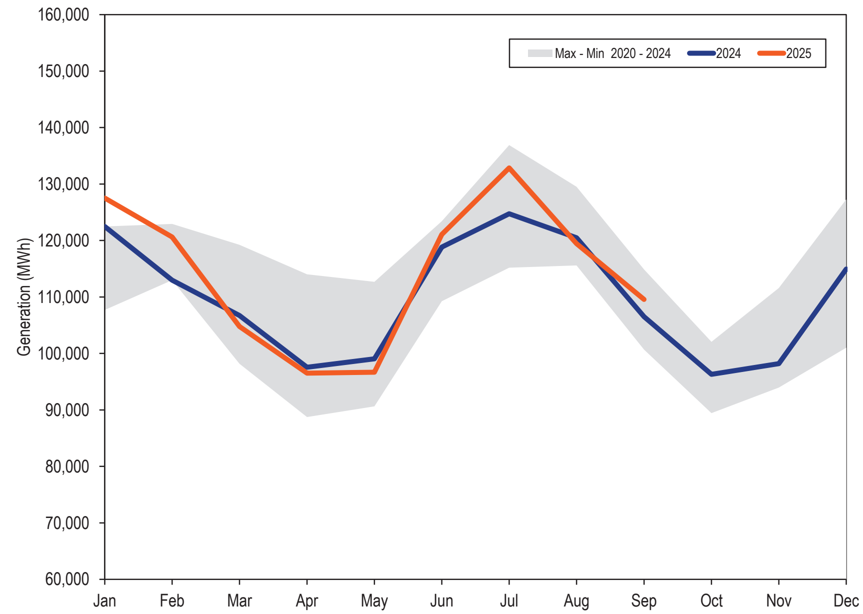
Table 3-4 Day-ahead hourly average cleared supply and cleared supply plus imports: January through September, 2001 through 2025

	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%)
2024	112,192	19,975	112,477	20,061	(6.4%)	8.7%	(6.4%)	8.9%
2025	114,328	20,898	114,585	20,951	1.9%	4.6%	1.9%	4.4%

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 in 2024 and the first nine months of 2025 with the historic five year range. The monthly average day-ahead cleared supply from January of 2025 was higher than the maximum of the past five years.

Figure 3-6 Day-ahead monthly average cleared supply: 2024 through September 2025



Real-Time and Day-Ahead Supply

Table 3-5 presents summary statistics for day-ahead and real-time cleared supply in the first nine months of 2024 and 2025. 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 real-time cleared supply includes real-time generation and real-time imports. The total day-ahead cleared supply includes physical day-ahead generation, INCs, UTCs, and day-ahead imports.

The total physical day-ahead average generation less the total physical real-time average generation in the first nine months of 2025 decreased 346 MWh from the first nine months of 2024, from -653 MWh to -999 MWh. The total day-ahead average supply less the total real-time average supply in the first nine months of 2025 decreased 1,316 MWh from the first nine months of 2024, from 13,883 MWh to 12,567 MWh.

Table 3-5 Day-ahead and real-time hourly cleared supply (MWh): January through September, 2024 and 2025

		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	2024	96,301	4,886	11,005	285	112,477	96,954	98,593	(653)	13,883
	2025	99,137	5,297	9,894	257	114,585	100,136	102,018	(999)	12,567
Median	2024	92,652	4,788	10,785	250	109,722	93,930	95,474	(1,278)	14,248
	2025	95,452	5,234	9,596	198	111,246	96,704	98,361	(1,252)	12,885
Standard Deviation	2024	17,823	1,681	4,394	249	20,061	16,635	16,917	1,189	3,144
	2025	18,693	1,734	3,504	228	20,951	18,290	18,551	403	2,400
Peak Average	2024	104,395	5,617	12,903	358	123,273	104,367	106,270	29	17,003
	2025	107,319	6,106	11,340	310	125,075	107,890	109,926	(572)	15,150
Peak Median	2024	100,381	5,529	12,650	315	119,613	100,820	102,576	(439)	17,038
	2025	104,073	5,960	11,074	259	121,688	104,759	106,529	(686)	15,160
Peak Standard Deviation	2024	17,202	1,588	4,054	291	17,580	16,090	16,364	1,112	1,216
	2025	18,208	1,592	3,215	250	18,980	17,948	18,166	260	814
Off-Peak Average	2024	89,202	4,245	9,341	221	103,009	90,453	91,861	(1,251)	11,148
	2025	91,983	4,590	8,629	211	105,413	93,356	95,104	(1,373)	10,309
Off-Peak Median	2024	86,704	4,157	8,727	200	99,777	88,183	89,466	(1,479)	10,311
	2025	88,979	4,500	8,280	155	102,154	90,331	91,908	(1,353)	10,246
Off-Peak Standard Deviation	2024	15,132	1,488	3,988	183	17,103	14,211	14,330	921	2,773
	2025	15,982	1,532	3,248	195	18,097	15,712	15,940	270	2,157

Figure 3-7 shows the average cleared volumes of day-ahead and real-time supply by hour of the day for the first nine months of 2025. 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, 2025

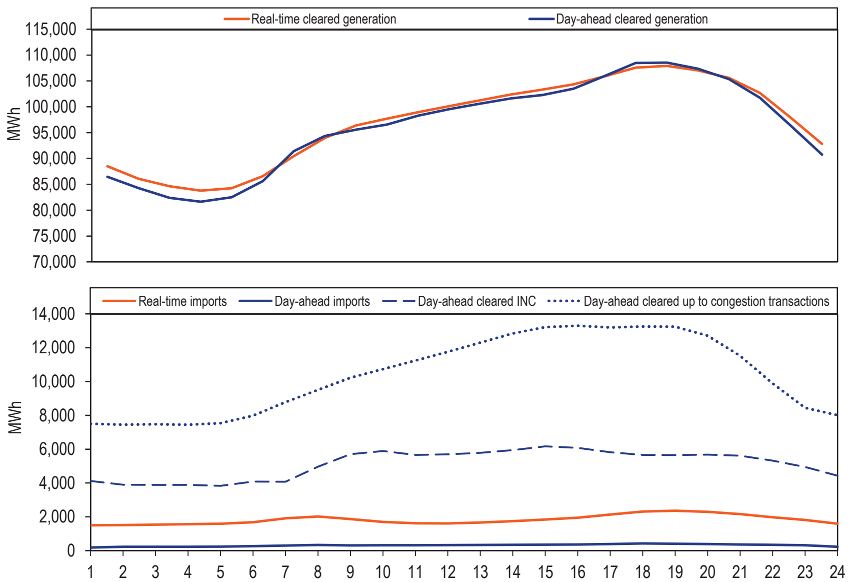
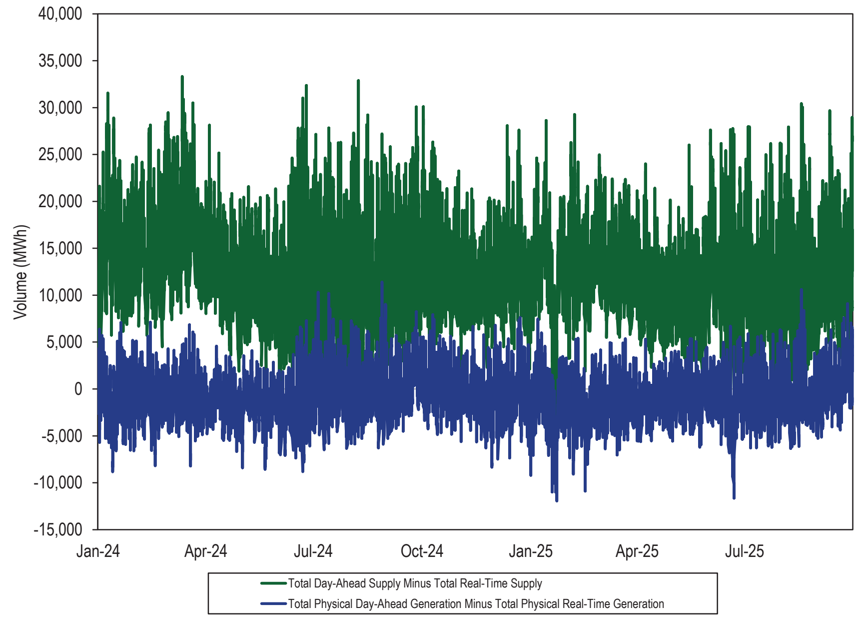


Figure 3-8 shows the difference between day-ahead and real-time daily average cleared supply in 2024 and the first nine months of 2025. The blue line is the total physical day-ahead generation less the total physical real-time generation, and the green line is the total day-ahead cleared supply less the total real-time cleared supply. The total real-time cleared supply includes real-time generation and real-time imports. The total day-ahead cleared supply includes physical day-ahead generation, INCs, UTCs, and day-ahead imports.

Figure 3-8 Difference between day-ahead and real-time daily average cleared supply: 2024 through September 2025



Demand

In the real-time energy market, demand includes physical load and exports. In the day-ahead energy market, demand includes physical load, exports, and virtual transactions.

Peak Demand

In the real-time energy market, demand refers to physical accounting load and exports, and in the day-ahead energy market, demand also includes virtual demand transactions.[29]

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.

Table 3-6 shows the seasonal peak load, net exports, real-time generation and the LMP for the peak load hour from 2004 through September 2025.

The winter peak load in 2025 was 140,043 MWh in the HE 0900 (EPT) on January 22, 2025, higher than the winter peak load in 2024, which was 130,293 MWh in the HE 0900 (EPT) on January 17, 2024. This was the highest winter peak load since the start of the PJM market.

The summer peak load in the first nine months of 2025 was 156,256 MWh in the HE 1800 (EPT) on June 23, 2025, higher than the summer peak load in 2024, which was 144,245 MWh in the HE 1800 (EPT) on June 21, 2024. This was the highest summer peak load since the start of the PJM market.

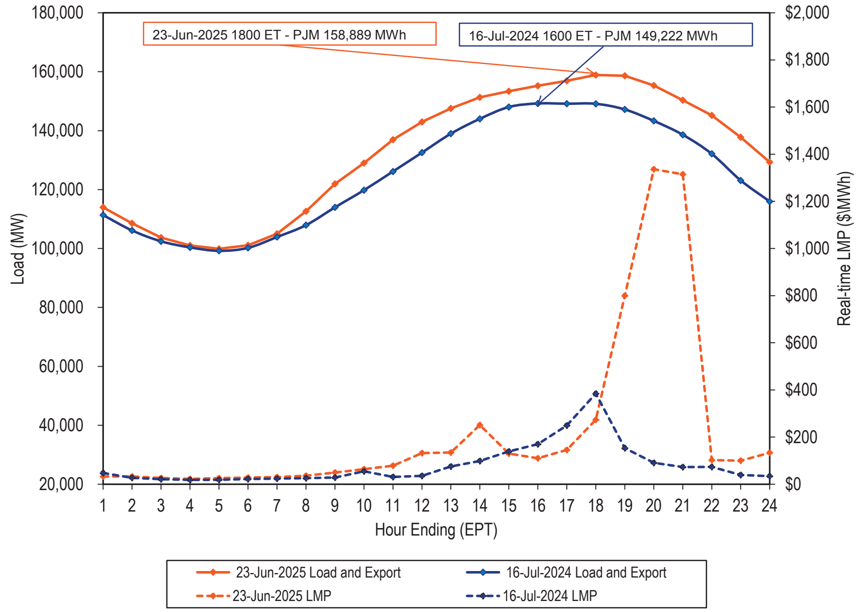
Table 3-6 Actual PJM peak load by season: 2004 through September 2025[30 31]

Summer Peak Load Hour						Winter Peak Load Hour					
Date	Hour Ending	RT Load (MWh)	Net Export (MWh)	RT Generation (MWh)	LMP ($/MWh)	Date	Hour Ending	RT Load (MWh)	Net Export (MWh)	RT Generation (MWh)	LMP ($/MWh)
Tuesday, August 03, 2004	17	77,950	435	78,666	$90.55	Monday, December 20, 2004	19	96,838	1,796	98,797	$129.90
Tuesday, July 26, 2005	16	134,017	(2,206)	131,975	$156.02	Wednesday, December 14, 2005	19	110,632	(376)	110,406	$163.45
Wednesday, August 02, 2006	17	144,904	(782)	143,957	$404.80	Friday, December 08, 2006	19	106,866	873	108,002	$83.17
Wednesday, August 08, 2007	16	136,368	404	140,170	$471.98	Monday, February 05, 2007	20	119,072	(3,964)	115,252	$178.18
Monday, June 09, 2008	17	127,216	2,862	125,804	$155.67	Thursday, January 03, 2008	19	109,239	(641)	112,339	$130.11
Monday, August 10, 2009	17	123,900	163	127,229	$85.64	Friday, January 16, 2009	19	114,765	(2,316)	115,093	$80.73
Tuesday, July 06, 2010	17	133,297	(247)	136,442	$194.02	Tuesday, December 14, 2010	19	113,121	(1,688)	115,284	$137.02
Thursday, July 21, 2011	17	154,095	(5,906)	151,790	$162.28	Monday, January 24, 2011	8	108,156	(1,218)	109,394	$176.49
Tuesday, July 17, 2012	17	150,879	(4,825)	149,582	$203.72	Tuesday, January 03, 2012	19	119,450	109	122,802	$67.07
Thursday, July 18, 2013	17	153,790	(7,607)	149,806	$244.92	Tuesday, January 22, 2013	19	123,473	(3,412)	123,283	$119.20
Tuesday, June 17, 2014	18	138,448	(7,382)	134,914	$113.51	Tuesday, January 07, 2014	19	136,932	(9,127)	131,731	$386.36
Tuesday, July 28, 2015	17	140,266	(3,942)	139,450	$101.40	Friday, February 20, 2015	8	139,647	(6,994)	137,504	$381.93
Thursday, August 11, 2016	16	148,577	1,235	153,820	$128.83	Thursday, December 15, 2016	19	127,759	(2,946)	128,979	$107.06
Wednesday, July 19, 2017	18	142,387	3,166	148,409	$59.49	Monday, January 09, 2017	8	124,210	(1,054)	126,761	$67.72
Tuesday, August 28, 2018	17	147,042	3,238	154,067	$131.36	Friday, January 05, 2018	19	133,851	(403)	137,173	$164.15
Friday, July 19, 2019	18	148,228	3,253	154,542	$37.47	Thursday, January 31, 2019	8	134,060	1,077	138,744	$85.21
Monday, July 20, 2020	17	141,449	6,013	150,667	$74.91	Wednesday, January 22, 2020	8	116,761	4,230	123,609	$31.76
Tuesday, August 24, 2021	17	145,563	2,984	151,708	$243.98	Friday, January 29, 2021	9	114,457	3,200	120,648	$27.87
Wednesday, July 20, 2022	18	144,356	3,190	151,620	$204.29	Friday, December 23, 2022	19	131,474	3,340	136,132	$2,011.80
Thursday, July 27, 2023	18	144,215	7,211	151,896	$110.52	Friday, February 03, 2023	20	117,705	746	121,952	$56.22
Tuesday, July 16, 2024	18	148,890	508	152,864	$384.56	Wednesday, January 17, 2024	9	130,293	9,291	143,324	$103.66
Monday, June 23, 2025	18	156,256	2,533	162,599	$273.39	Wednesday, January 22, 2025	9	140,043	7,660	151,437	$355.76

30 Peak loads shown are accounting load, without losses. 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 load plus net exports on the peak load days for the first nine months of 2024 and 2025. The real-time average LMP for July 16, 2024, peak load hour was $33.90 per MWh, and for June 23, 2025, peak load hour it was $273.39 per MWh.

Figure 3-9 Peak load and net export day comparison



Real-Time Demand

In the PJM Real-Time Energy Market, there are two types of demand:[32]

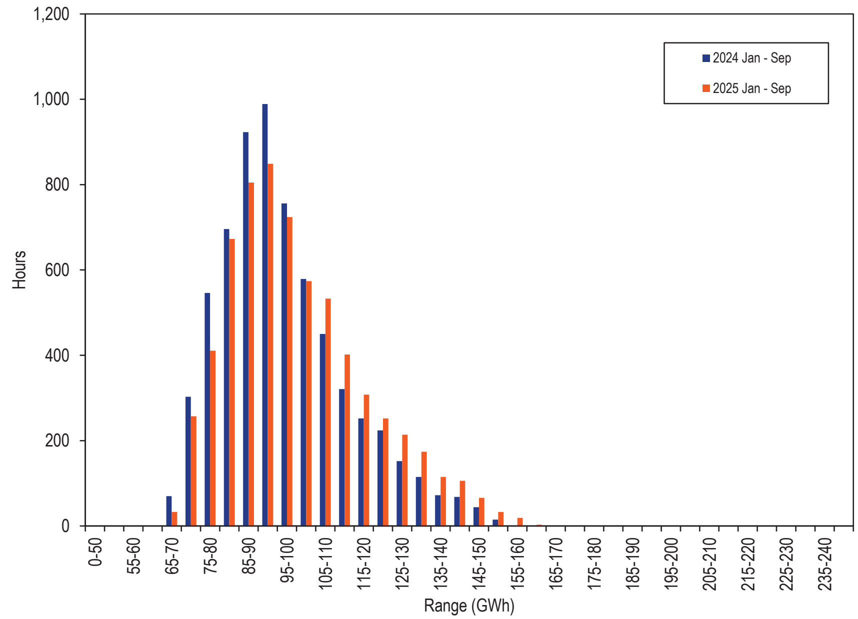
- **Load.** The actual MWh level of energy used by load within PJM.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. A real-time export must have a valid OASIS reservation when offered, must have available ramp room to support the export, must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

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

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 2024 and 2025.[33]

Figure 3-10 Distribution of real-time load plus exports: January through September, 2024 and 2025[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 Demand

Table 3-7 presents real-time hourly demand summary statistics for the first nine months of 2001 through 2025.[35]

The real-time hourly average load in the first nine months of 2025 increased by 3.0 percent from the first nine months of 2024, from 90,917 MWh to 93,683 MWh.

The real-time hourly average demand including exports in the first nine months of 2025 increased by 3.5 percent from the first nine months of 2024, from 96,746 MWh to 100,114 MWh.

The real-time hourly average load in the first nine months of 2025 was the highest since the start of the PJM market for the first nine months of a year at 93,683 MWh.

Table 3-7 Real-time hourly average load and load plus exports: January through September, 2001 through 2025

	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	87,269	14,833	93,709	15,199	(3.6%)	(9.4%)	(2.6%)	(8.3%)
2024	90,917	16,529	96,746	16,478	4.2%	11.4%	3.2%	8.4%
2025	93,683	17,631	100,114	18,080	3.0%	6.7%	3.5%	9.7%

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.

PJM Real-Time Monthly Average Demand

Figure 3-11 compares the real-time monthly average load plus exports of 2024 and the first nine months of 2025 with the historic five year range. The real-time monthly average load plus exports in January, February, April, June and September 2025 was higher than the maximum monthly average load plus exports for the past five years.

Figure 3-11 Real-time monthly average hourly load plus exports: 2024 through September 2025

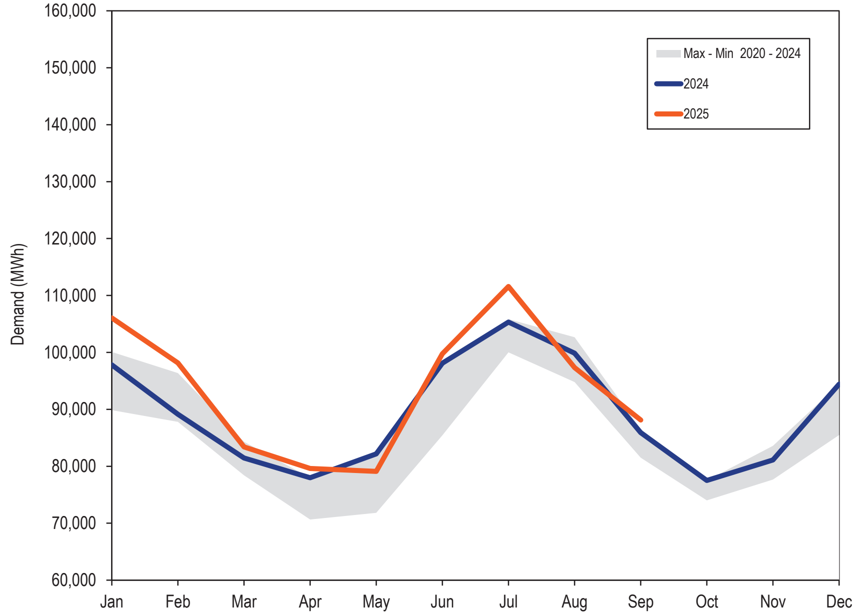
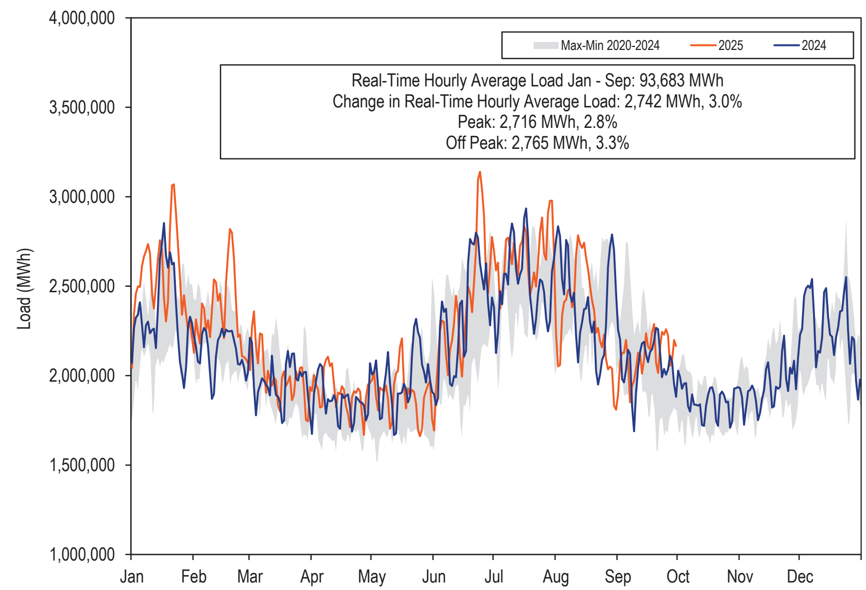


Figure 3-12 compares the real-time daily average load in 2024 and the first nine months of 2025, with the historic five year range. The daily average load in the first nine months of 2025 was higher than the historic five year range in January, February and June.

Figure 3-12 Real-time daily load: 2024 through September 2025



The real-time load is significantly affected by weather conditions. Table 3-8 compares the monthly heating and cooling degree days in 2024 and the first nine months of 2025.[36]

36 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings). Reference: <https://www.eia.gov/energyexplained/units-and-calculators/degree-days.php>. This calculation was modified starting in 2024 Q3 from the method used in prior State of the Market Reports which was the PJM calculation method based on 60 degrees for heating degree days and 65 degrees for cooling degree days.
Heating and cooling degree days are calculated by weighting the temperature at each weather station in the individual transmission zones using weights provided by PJM in Manual 19. Then the temperature is weighted by the real-time zonal accounting load for each transmission zone. After calculating an average hourly temperature across PJM, the heating and cooling degree formulas are used to calculate the daily heating and cooling degree days, which are summed for monthly reporting. The weather stations that provided the basis for the analysis are ABE, ACY, AVP, BWI, CAK, CLE, CMH, CRW, CVG, DAY, DCA, ERI, EWR, FWA, IAD, ILG, IPT, LEX, ORD, ORF, PHL, PIT, RIC, ROA, TOL and WAL.

Heating degree days increased 19.0 percent compared to the first nine months of 2024. Cooling degree days decreased 12.8 percent compared to the first nine months of 2024.

Table 3-8 Heating and cooling degree days: 2024 through September 2025

	2024		2025		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	799	0	985	0	23.3%	0.0%
Feb	562	0	720	0	28.1%	0.0%
Mar	381	0	370	2	(2.9%)	0.0%
Apr	157	18	173	10	10.1%	(43.6%)
May	9	98	21	31	137.3%	(68.8%)
Jun	0	326	1	302	0.0%	(7.4%)
Jul	0	408	0	433	0.0%	6.1%
Aug	0	326	0	242	0.0%	(25.9%)
Sep	0	152	0	139	0.0%	(9.0%)
Oct	94	11				
Nov	310	2				
Dec	699	0				
Jan-Sep	1,909	1,329	2,270	1,158	19.0%	(12.8%)

Day-Ahead Demand

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

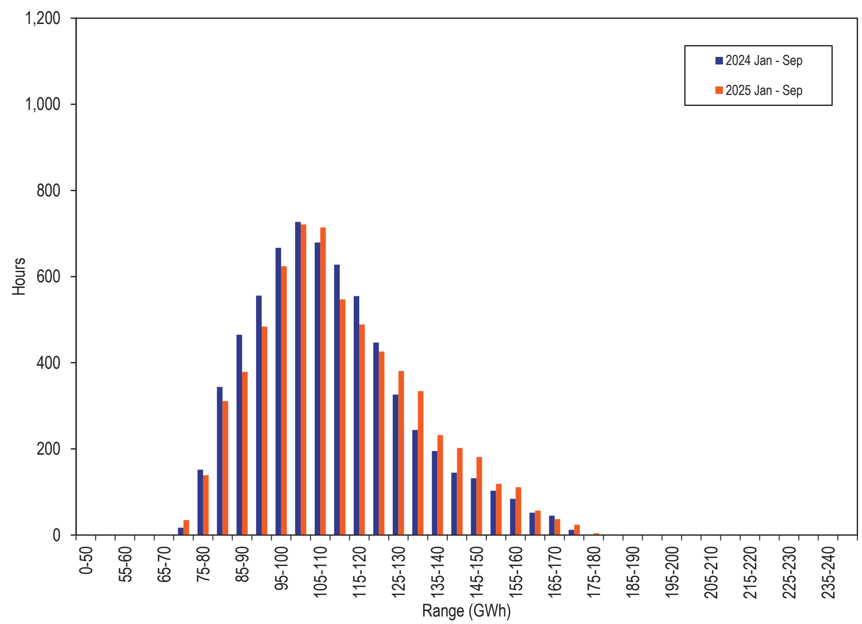
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of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

PJM Day-Ahead Demand Duration

Figure 3-13 shows the hourly distribution of the day-ahead cleared demand including DECs, UTCs and exports for the first nine months of 2024 and 2025.

Figure 3-13 Distribution of day-ahead cleared demand plus exports: January through September, 2024 and 2025[37]



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

PJM Day-Ahead Average Demand

Table 3-9 shows day-ahead hourly average cleared demand including DECs, UTCs and exports for the first nine months of 2001 through 2025.

The day-ahead hourly average cleared demand in the first nine months of 2025, including DECs and UTCs, increased by 1.4 percent from the first nine months of 2024, from 106,355 MWh to 107,864 MWh.

The day-ahead hourly average cleared demand in the first nine months of 2025, including DECs, UTCs and exports, increased by 1.9 percent from the first nine months of 2024, from 110,189 MWh to 112,308 MWh.

Table 3-9 Day-ahead hourly average cleared demand and demand plus exports: January through September, 2001 through 2025

	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%)
2024	106,355	19,453	110,189	19,559	(6.5%)	9.0%	(6.4%)	8.8%
2025	107,864	20,202	112,308	20,469	1.4%	3.9%	1.9%	4.7%

PJM Day-Ahead Monthly Average Demand

Figure 3-14 compares the day-ahead monthly average cleared demand including DECs and UTCs for 2024 and the first nine months of 2025, with the historic five year range. In January 2025, the day-ahead monthly average cleared demand was higher than the maximum of the past five years.

Figure 3-14 Day-ahead monthly average cleared demand: 2024 through September 2025

Real-Time and Day-Ahead Demand

Table 3-10 presents summary statistics for day-ahead and real-time cleared demand for the first nine months of 2024 and 2025. The last two columns of Table 3-10 are day-ahead cleared demand minus real-time cleared demand. The first column is the total physical day-ahead load (fixed demand plus cleared price-sensitive demand) less the physical real-time load. The second column is the total cleared day-ahead demand less the total cleared real-time demand.

The total physical day-ahead average load less the total physical real-time average load in the first nine months of 2025 decreased 288 MWh from the first nine months of 2024, from -1,014 MWh to -1,302 MWh. The total day-ahead average demand less the total real-time average demand in the first nine months of 2025 decreased 1,249 MWh from the first nine months of 2024, from 13,443 MWh to 12,194 MWh.

Table 3-10 Day-ahead and real-time demand (MWh): January through September, 2024 and 2025

		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	2024	89,529	375	5,446	11,005	3,835	110,189	90,917	96,746	(1,014)	13,443
	2025	91,975	407	5,589	9,894	4,445	112,308	93,683	100,114	(1,302)	12,194
Median	2024	86,498	372	5,206	10,785	3,789	107,476	87,953	93,723	(1,084)	13,753
	2025	88,767	400	5,320	9,596	4,358	109,019	90,530	96,618	(1,363)	12,401
Standard Deviation	2024	16,317	61	1,827	4,394	1,056	19,559	16,529	16,478	(150)	3,081
	2025	17,083	86	2,004	3,504	1,137	20,469	17,631	18,080	(462)	2,389
Peak Average	2024	97,603	384	6,085	12,903	3,801	120,776	98,693	104,272	(707)	16,503
	2025	99,971	426	6,359	11,340	4,489	122,586	101,452	107,857	(1,055)	14,729
Peak Median	2024	94,039	381	5,943	12,650	3,760	117,273	94,661	100,704	(241)	16,569
	2025	96,890	422	6,209	11,074	4,344	119,258	98,093	104,605	(781)	14,653
Peak Standard Deviation	2024	15,270	58	1,743	4,054	1,073	17,124	15,721	15,919	(393)	1,205
	2025	16,219	86	1,955	3,215	1,214	18,543	16,963	17,691	(657)	852
Off-Peak Average	2024	82,449	367	4,885	9,341	3,864	100,906	84,098	90,146	(1,283)	10,760
	2025	84,982	390	4,915	8,629	4,406	103,322	86,890	93,344	(1,518)	9,978
Off-Peak Median	2024	79,906	357	4,588	8,727	3,811	97,795	81,656	87,876	(1,393)	9,919
	2025	82,065	379	4,603	8,280	4,367	100,091	83,805	90,319	(1,362)	9,772
Off-Peak Standard Deviation	2024	13,712	63	1,711	3,988	1,041	16,628	14,020	13,937	(245)	2,691
	2025	14,568	83	1,791	3,248	1,064	17,652	15,239	15,519	(588)	2,133

Figure 3-15 shows the average cleared volumes of day-ahead and real-time demand for the first nine months of 2025. 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 3-15 Day-ahead and real-time demand (Average hourly volumes): January through September, 2025

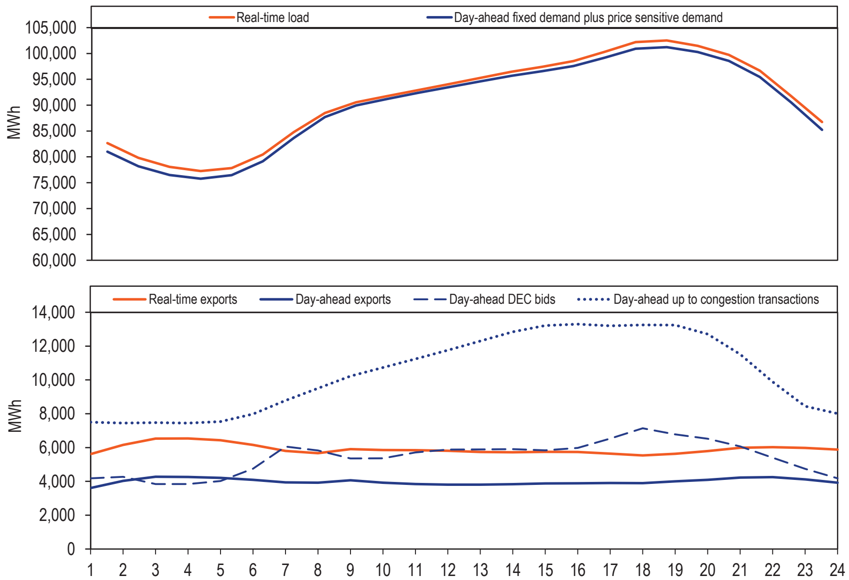


Figure 3-16 shows the difference between the physical day-ahead load and the physical real-time load, and the difference between the day-ahead demand including DECs, UTCs, and exports, and the real-time demand including exports, for 2024 and the first nine months of 2025.

Figure 3-16 Day-ahead minus real-time daily demand: 2024 through September 2025

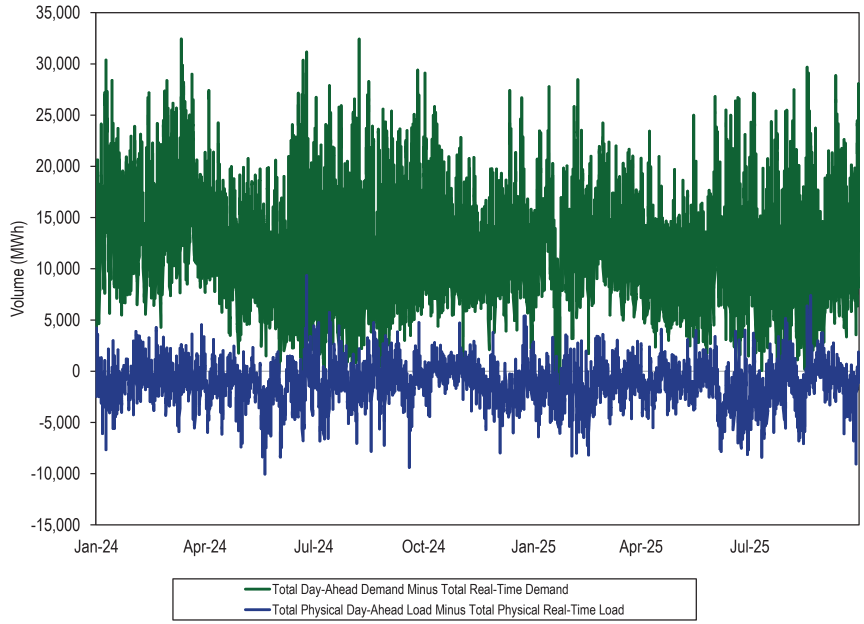


Figure 3-17 shows the difference between the day-ahead and real-time hourly average load by hour of the day. DECs, UTCs and exports are not included. The largest difference generally occurs during off peak hours, especially at hours beginning 1 and 2. The smallest difference generally occurs during peak hours, especially at hours beginning 9 and 10.

Figure 3-17 Difference between day-ahead and real-time hourly average physical load by hour of the day (Average hourly volumes): January through September, 2021 through 2025

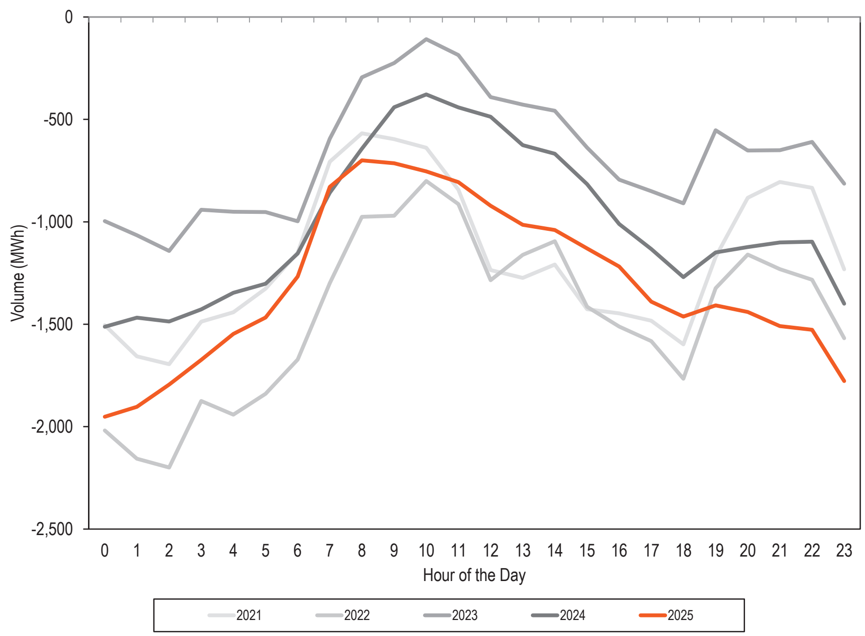


Figure 3-18 shows the difference between the day-ahead and real-time on peak and off peak hourly average physical load by month. DECs, UTCs and exports are not included.

Figure 3-18 Difference between day-ahead and real-time on peak and off peak hourly average physical load by month: 2021 through September 2025

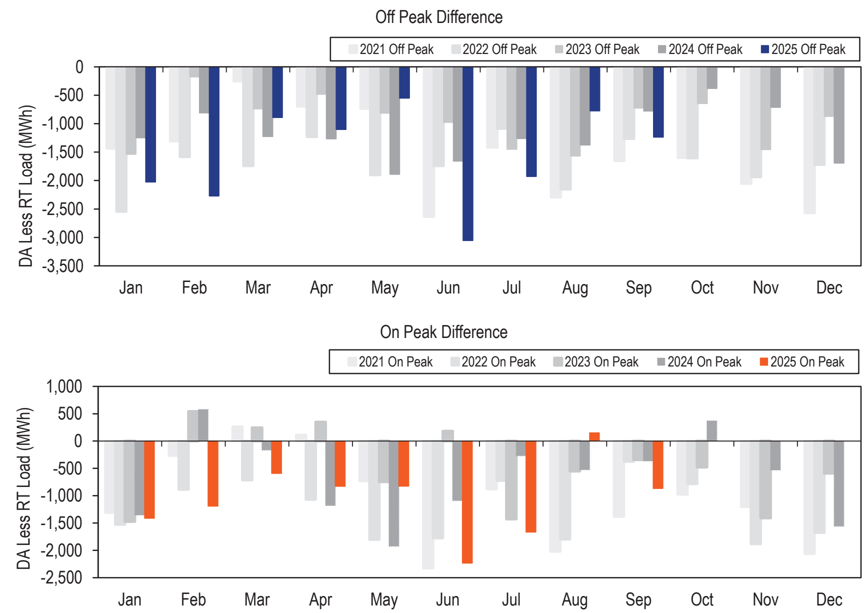


Table 3-11 shows the difference between the day-ahead and real-time on peak and off peak physical load by zone. DECs, UTCs and exports are not included. Some zones showed larger difference than other zones, such as DOM, BGE and APS. Some zones did not show a big difference between on peak and off peak, such as DOM and AEP. Some zones showed a significant difference between on peak and off peak, such as AECO and JCPL.

Table 3-11 Difference between day-ahead and real-time on peak and off peak physical load by zone

	2024 Jan-Sep				2025 Jan-Sep			
	Off Peak		On Peak		Off Peak		On Peak	
Zone	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load
AECO	16.99	1.8%	44.29	4.2%	(8.22)	(0.1%)	10.16	2.3%
AEP	(109.20)	(0.8%)	(81.44)	(0.5%)	(48.63)	(0.2%)	(11.11)	0.0%
APS	(93.39)	(1.7%)	(8.72)	(0.1%)	(70.30)	(1.1%)	1.52	0.2%
ATSI	(110.02)	(1.4%)	42.02	0.7%	(41.47)	(0.3%)	50.52	0.8%
BGE	(140.25)	(4.2%)	(149.69)	(3.8%)	(135.72)	(3.8%)	(141.70)	(3.3%)
COMED	7.72	0.3%	17.77	0.4%	(29.43)	(0.1%)	(56.16)	(0.2%)
DAY	(13.32)	(0.4%)	(7.73)	(0.1%)	(19.40)	(0.8%)	(14.16)	(0.4%)
DOM	(431.64)	(3.3%)	(447.02)	(3.0%)	(745.43)	(5.2%)	(793.17)	(5.0%)
DPL	(34.17)	(1.7%)	(27.54)	(1.0%)	(41.63)	(2.0%)	(36.49)	(1.3%)
DUQ	9.48	0.7%	28.14	1.7%	6.71	0.8%	38.24	2.8%
EKPC/DEOK	(46.52)	(0.9%)	(25.67)	(0.4%)	(32.76)	(0.6%)	13.91	0.3%
JCPL	(40.13)	(1.4%)	50.50	3.1%	(44.18)	(1.5%)	17.25	1.7%
METED	9.96	0.9%	26.12	1.6%	15.14	1.3%	26.30	1.7%
PECO	(28.69)	(0.5%)	(29.31)	(0.3%)	(27.61)	(0.4%)	(6.59)	0.1%
PENELEC	(7.48)	(0.3%)	9.79	0.6%	(3.60)	0.1%	12.51	0.9%
PEPCO	(114.28)	(3.9%)	(117.52)	(3.3%)	(107.71)	(3.4%)	(94.98)	(2.4%)
PPL	33.72	1.0%	81.15	1.8%	(29.14)	(0.5%)	4.38	0.4%
PSEG	(173.35)	(3.6%)	(93.10)	(1.3%)	(142.36)	(2.9%)	(63.51)	(0.6%)
RECO	(5.37)	(3.8%)	(6.05)	(2.9%)	0.53	0.5%	1.41	1.2%

Table 3-12 shows the difference between the day ahead and real-time physical load by zone for the last five years. DECs, UTCs and exports are not included. Some zones showed a change from year to year, such as AECO, PEPCO. The largest difference between day ahead load and real time load was in DOM with -767.70 MW, -5.1 percent of real-time load in the first nine months of 2025.

Table 3-12 Difference between day ahead and real-time physical load by zone: January through September, 2021 through 2025

	2021 Jan-Sep		2022 Jan-Sep		2023 Jan-Sep		2024 Jan-Sep		2025 Jan-Sep	
Zone	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load	Average DA-RT Difference	Average Percent of RT Load
AECO	(40.02)	(2.2%)	(41.73)	(2.2%)	9.39	1.3%	29.75	2.9%	0.36	1.0%
AEP	(98.79)	(0.7%)	(134.42)	(1.0%)	(73.93)	(0.4%)	(96.23)	(0.7%)	(31.13)	(0.1%)
APS	(54.33)	(0.9%)	(97.87)	(1.7%)	(109.05)	(1.9%)	(53.83)	(0.9%)	(36.80)	(0.5%)
ATSI	(15.12)	0.1%	(101.32)	(1.2%)	16.05	0.4%	(38.98)	(0.4%)	1.44	0.2%
BGE	(147.61)	(3.9%)	(93.35)	(2.6%)	(80.01)	(2.3%)	(144.66)	(4.0%)	(138.51)	(3.6%)
COMED	(20.41)	0.2%	(53.20)	(0.3%)	144.35	1.5%	12.41	0.3%	(41.90)	(0.2%)
DAY	(1.20)	0.2%	(37.57)	(1.7%)	20.59	1.3%	(10.71)	(0.3%)	(16.96)	(0.6%)
DOM	(506.75)	(4.2%)	(601.12)	(4.8%)	(626.85)	(4.9%)	(438.82)	(3.2%)	(767.70)	(5.1%)
DPL	(49.14)	(2.1%)	(65.47)	(3.0%)	(29.24)	(1.3%)	(31.07)	(1.4%)	(39.23)	(1.6%)
DUQ	4.69	0.5%	(90.70)	(5.7%)	24.98	1.8%	18.20	1.1%	21.42	1.7%
EKPC/DEOK	(46.49)	(0.8%)	(76.47)	(1.6%)	(42.19)	(0.8%)	(36.78)	(0.7%)	(10.99)	(0.2%)
JCPL	(35.47)	(0.5%)	(39.26)	(0.7%)	16.34	1.2%	2.22	0.7%	(15.52)	(0.0%)
METED	(19.17)	(0.7%)	(62.02)	(3.1%)	17.85	1.2%	17.51	1.2%	20.34	1.5%
PECO	(39.69)	(0.4%)	83.77	2.1%	50.05	1.5%	(28.98)	(0.4%)	(17.80)	(0.2%)
PENELEC	9.41	0.5%	10.90	0.6%	33.71	1.9%	0.59	0.1%	3.92	0.5%
PEPCO	(18.32)	(0.2%)	(20.31)	(0.6%)	(38.30)	(1.0%)	(115.80)	(3.6%)	(101.77)	(2.9%)
PPL	(46.75)	(0.8%)	32.06	0.9%	64.64	1.6%	55.88	1.4%	(13.50)	(0.1%)
PSEG	(43.63)	(0.7%)	(57.58)	(0.8%)	(59.41)	(1.1%)	(135.86)	(2.5%)	(105.58)	(1.8%)
RECO	6.47	4.3%	(1.53)	(0.9%)	(0.60)	0.3%	(5.69)	(3.4%)	0.94	0.8%

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 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 determine whether to commit them based on their offers.

The Must Run column in Table 3-13 is the submitted offer MW of units offering with must run commitment status. The Eco Min column in Table 3-13 is the economic minimum MW of units offering with economic commitment status. The dispatchable range in Table 3-13 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.[38] Table 3-13 shows that 0.1 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 for the first nine months of 2025, 22.4 percent of MW were offered as must run, 33.0 percent of MW were offered as the economic minimum MW for dispatchable units, 44.4 percent of MW were offered as dispatchable, and 0.1 percent of MW were offered as emergency maximum MW.

Table 3-13 Dispatchable status of day-ahead energy offers: January through September, 2025

			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	9.2%	34.9%	0.4%	30.9%	14.2%	2.8%	1.3%	3.2%	2.6%	0.2%	0.1%	0.1%	0.1%	55.8%
CT	0.4%	58.4%	0.1%	2.7%	12.0%	7.0%	3.9%	9.9%	4.9%	0.3%	0.0%	0.1%	0.3%	40.9%
Diesel	0.0%	87.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	12.3%	-0.0%	0.0%	-0.0%	0.0%	12.3%
Hydro	81.7%	0.6%	17.7%	0.0%	-0.0%	0.0%	-0.0%	0.0%	0.0%	-0.0%	-0.0%	0.0%	0.0%	17.7%
Nuclear	83.6%	14.8%	1.8%	-0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%
Solar	14.1%	0.1%	68.9%	7.2%	4.7%	2.0%	0.7%	1.0%	0.6%	0.4%	0.0%	0.4%	0.0%	85.8%
Steam - Coal	27.0%	27.3%	0.1%	13.3%	24.7%	3.2%	0.7%	0.3%	0.9%	2.3%	0.0%	0.0%	0.2%	45.5%
Steam - Other	5.4%	22.8%	2.1%	14.6%	15.5%	7.6%	1.5%	11.3%	18.4%	0.5%	0.0%	0.0%	0.1%	71.7%
Wind	1.6%	0.1%	73.1%	7.9%	8.2%	2.3%	3.1%	0.7%	1.2%	1.2%	0.1%	0.5%	0.0%	98.3%
Other	12.9%	51.6%	4.8%	4.8%	7.2%	0.1%	0.1%	1.4%	15.9%	0.5%	0.0%	0.0%	0.6%	34.9%
All Units	22.4%	33.0%	3.1%	15.2%	12.6%	3.6%	1.6%	4.2%	3.5%	0.5%	0.0%	0.1%	0.1%	44.4%

38 "PJM Manual 11: Energy & Ancillary Services Market Operations," Rev. 136. (Oct. 1, 2025). § 2.3.3.2 (Generator Schedules) "Designation of all or part of a unit's capacity as Maximum Emergency (ME) constitutes withholding in the Day-ahead Market, if The capacity is not designated as ME in the bid for the Real-time Market, or; There is no physical reason to designate the unit as ME."

Hourly Offers and Intraday Offer Updates

All participants may make specific hourly offers. Hourly offers mean that participants can specify different MW and price pairs for each hour of the day. Hourly offers can be submitted in the day-ahead market and offers may be updated in the real-time market. Participants must opt in on a monthly basis to make intraday offer updates in real time. Participants that have opted in can make updates only based on the process defined in their fuel cost policies. Units typically use hourly offers to reflect the two gas days in a power day. A gas day is from 10:00 AM EPT to 10:00 AM EPT the next day. Therefore, gas fired units may face two different gas prices. Typically, gas units have one offer from 00:00 EPT until 10:00 EPT and a different offer from 10:00 EPT until 24:00 EPT. Units typically use intraday updates to reflect changes in gas costs that occur in real time.

Table 3-14 shows the daily average number of units that make hourly offers in the day-ahead market, that opted in to intraday offer updates and that make intraday offer updates. In the first nine months of 2025, an average of 373 units per day made hourly offers, an increase of seven units from the first nine months of 2024. In the first nine months of 2025, 612 units opted in for intraday offer updates, an increase of 26 units from the first nine months of 2024. In the first nine months of 2025, an average of 163 units made intraday offer updates each day, an increase of 15 units from the first nine months of 2024.

Table 3-14 Daily average number of units making hourly offers, opted in for intraday offers and making intraday offer updates: January through September, 2024 and 2025

	Fuel Type	2024 (Jan-Sep)	2025 (Jan-Sep)	Difference
Hourly Offers	Natural Gas	321	322	1
	Other Fuels	45	51	6
	Total	366	373	7
Opt In	Natural Gas	434	435	1
	Other Fuels	152	177	25
	Total	586	612	26
Intraday Offer Updates	Natural Gas	144	160	16
	Other Fuels	4	3	(1)
	Total	148	163	15
Total Units with nonzero offers		834	851	17

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.[39] 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. The categorical exemption for intermittent resources, capacity storage resources, and hybrid resources from the capacity market must offer requirement was eliminated in February 2025.[40] Only demand resources are exempt from the capacity market must offer requirement.

The MMU recommends that all capacity resources have a must offer obligation. The MMU also recommends that performance penalties not be applied to solar and wind resources when they are not capable of performing based on ambient conditions. For example, solar resources should be subject to performance penalties if they fail to perform when the sun is shining but should not be subject to performance penalties in the middle of the night. This would be a rational application of the PAI penalties that recognizes the physical capabilities of resources and is therefore not discriminatory, in contrast to PJM's current treatment of such resources.

The current enforcement of the ICAP must offer requirement is inadequate.[41] 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 via Markets Gateway. 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)

39 OA Schedule 1 § 1.10.1A(d).

40 FERC approved extending the RPM must offer requirement to intermittent resources, capacity storage resources, and hybrid resources but not to demand resources on February 20, 2025. 190 FERC ¶ 61,117.

41 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.

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.

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.

The MMU recommended that intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources. In 2023, the MMU and PJM proposed to require intermittent resources to offer their median forecast on an hourly basis in the day-ahead and real-time energy market. This proposal was implemented on November 15, 2023.[42]

The MMU recommends that storage resources also be subject to an enforceable ICAP must offer requirement that reflects the limitations of these resources.

Table 3-15 shows average hourly MW, for each month, that violated the ICAP must offer requirement in the first nine months of 2025. On average for all hours, 1,905 MW did not meet the ICAP must offer requirement, but for 10 percent of the hours, 3,098 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.

42 *See* "Renewable Dispatch Markets Manual Changes," PJM presentation to the Markets and Reliability Committee. (November 15, 2023) <https://www.pjm.com/-/media/committees-groups/committees/mrc/2023/20231115/20231115-consent-agenda-f---1-manual-11-revisions---renewable-dispatch---presentation.ashx>.

Table 3-15 Average hourly estimated capacity (MW) failing the ICAP must offer requirement: January through September, 2025

Month	90th Percentile	Average	10th Percentile
Jan-25	2,872	1,833	956
Feb-25	2,859	2,140	1,488
Mar-25	3,418	2,690	1,996
Apr-25	3,540	2,682	1,801
May-25	3,691	2,880	2,237
Jun-25	1,870	1,358	864
Jul-25	2,390	1,820	1,426
Aug-25	1,242	923	578
Sep-25	1,121	815	533
2025	3,098	1,905	798

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.[43]

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.[44]

The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy.[45] Capacity resources should offer their full output in the energy market and be 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 3-16 shows average hourly maximum emergency MW, for each month. The levels of maximum emergency MW change hourly, daily and seasonally. For example, in July 2025, 10 percent of hours had maximum emergency MW greater than or equal to 701 MW while 10 percent of hours had maximum emergency MW less than 227 MW. The hourly average, in the first nine months of 2025, was 344 MW offered as maximum emergency, 38.6 percent lower than in the first nine months of 2024.

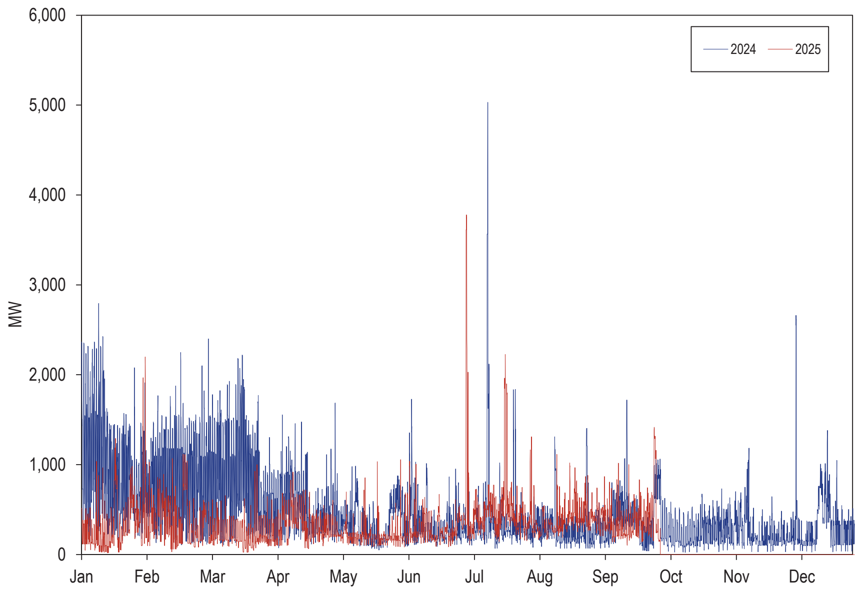
Table 3-16 Maximum emergency MW by month: January through September, 2025

Month	90th Percentile	Average	10th Percentile
Jan-25	680	338	97
Feb-25	728	399	120
Mar-25	430	254	97
Apr-25	601	350	165
May-25	307	214	130
Jun-25	464	280	154
Jul-25	701	506	227
Aug-25	551	384	258
Sep-25	592	377	189
2025	589	344	140

Figure 3-19 shows maximum emergency MW by hour in 2024 and the first nine months of 2025. The continued reduction of the use of emergency maximum that started in 2024 is mainly a result of improved compliance with the maximum emergency rules. The increases in maximum emergency MW are typically from short term situations at generators, such as testing of equipment which can be suspended in the event of a system emergency or operational restrictions such as limited run hours due to environmental permits.

43 See 151 FERC ¶ 61,208 at P 476 (2015).
44 OA Schedule 1 § 1.10.1A(d).
45 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).

Figure 3-19 Maximum Emergency MW by hour: 2024 and January through September, 2025



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 make price-based offers are required to make available at least one price-based parameter limited offer (referred to as price-based PLS). The prices in a price-based PLS offer are at the discretion of the seller but the parameters are the same parameters used in the cost-based offers. 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.

Offer Schedule Selection

PJM's current process for selecting unit offers (schedules) does not prevent the exercise of market power through the use of markups or through the use of inflexible parameters. The goal of having parameter limited offers 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. The goal of having cost-based offers is to prevent the use of markups to exercise market power. Instead of ensuring the least cost solution, PJM frequently chooses the higher price-based schedule that includes no parameter limits rather than the cost-based schedule that includes parameter limits 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, but did not take corrective action in its November 30, 2023 order.[46] [47]

PJM raised the schedule selection issues in the stakeholder process to address computational time in the day-ahead market. PJM's original proposal would have weakened market power mitigation. FERC rejected PJM's proposal because PJM's proposal would create the ability for market sellers to exercise market power.[48] PJM filed and, on October 25, 2024, FERC accepted a revised proposal that would require that sellers that fail the TPS test be offer capped at their cost-based offers and that operating parameters be mitigated.[49] FERC accepted PJM's proposal that has no specific plans to implement the improved rules and instead links implementation to PJM's long delayed improvements to its combined cycle modelling. PJM's revised proposal also continues to use the flawed formula, which was the basis for the first proposal rejected

46 See 175 FERC ¶ 61,231 (2021).
47 See 185 FERC ¶ 61,158 (2023).
48 See 187 FERC 61,051 at P 25 (2024).
49 See 189 FERC ¶ 61,060 (2024).

by FERC, to select among cost-based offers. This will result in the illogical selection of cost-based offers in some circumstances, for example if a dual fuel unit submits offers for both oil and gas on a day when the economics change between the two fuels midday. PJM should modify its implementation to address that issue. The result would allow market sellers to select the correct cost-based fuel schedule. There is no reason to delay implementation until PJM addresses combined cycle modelling. The changes would decrease the solution time for the day-ahead market and enhance market efficiency. The new approach should be implemented as soon as possible.

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 2025. The analysis includes units with technologies that are subject to parameter limits and offer both price-based and cost-based schedules.[50] Table 3-17 shows the number and percentage of day-ahead unit run hours that failed the TPS test but were committed on price schedules. Table 3-17 shows that 29.3 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 3-17 Parameter mitigation for units failing the day-ahead TPS test: January through September, 2025

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	20,721	29.3%
Committed on price schedule as flexible as cost	3,953	5.6%
Committed on cost (cost capped)	43,515	61.6%
Committed on price PLS	2,447	3.5%
Total committed on schedule as flexible as cost	49,915	70.7%
Total failed TPS test commitments	70,636	100.0%

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market for units in zones with a cold weather alert, a hot weather alert, or a maximum generation emergency declaration in the first nine months of 2025. PJM declared cold weather alerts on 13 days and hot weather alerts on 18 days in the first nine months of 2025. 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 3-18 shows that 31.2 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. 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.

Table 3-18 Parameter mitigation during weather alerts: January through September, 2025

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	51,165	31.2%
Committed on price schedule as flexible as PLS	10,808	6.6%
Committed on cost (cost capped)	8,135	5.0%
Committed on price PLS	93,923	57.3%
Total committed on schedule as flexible as PLS	112,866	68.8%
Total weather alert commitments	164,031	100.0%

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.

50 Nuclear, wind, solar and hydro units are not subject to parameter limits.

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.

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 weather alerts or emergency conditions. PJM should always use cost-based offers for units that fail the TPS test, and always use flexible parameters in all price-based offers during weather alerts and emergencies. This approach would allow PJM to effectively mitigate inflexible operating parameters consistent with PJM's asserted processing time constraints. PJM's revised schedule selection proposal adopts this approach, but PJM has failed to propose an implementation date and the flawed rules remain in place as a result.

The MMU recommends that in order to ensure effective market power mitigation, PJM always use cost-based offers for units that fail the TPS test, and always use flexible parameters for all cost-based and all price-based offers during cold and hot weather alerts and emergency conditions.[51] [52]

Parameter Limits

The unit specific parameter limits for capacity resources are based on default minimum operating parameter limits posted by PJM by technology type, and any adjustments based on a unit specific review process. These default parameters were based on analysis by the MMU.

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. 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.

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.[53] 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 unit specific adjustments for some of the parameters. Table 3-19 shows, for the delivery year beginning June 1, 2025, the number of units with approved unit specific parameter limits, and the number of units that used the default parameter limits published by PJM.

51 *See* "Comments of the Independent Market Monitor for PJM," Docket No. EL21-78 (October 15, 2021) at 18 - 19.
52 *See* "Schedule Selection: IMM Package," IMM Presentation to the Markets Implementation Committee (September 6, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Schedule_Selection_IMM_Package_20230906.pdf>.
53 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>.

Table 3-19 Adjusted unit specific parameter limit statistics: 2025/2026 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	117	37	24.0%
Frame CT	149	106	41.6%
Combined Cycle	94	28	23.0%
Reciprocating Internal Combustion Engines	56	3	5.1%
Solid Fuel NUG	32	6	15.8%
Oil and Gas Steam	10	22	68.8%
Subcritical and Supercritical Coal Steam	7	64	90.1%
Total	465	266	36.4%

Parameter Limited Schedule Exceptions

There are three different types of exceptions to the parameter limited schedule default values: temporary exceptions, period exceptions, and persistent exceptions, each differentiated by the length of time it applies. Market sellers must submit requests for exceptions to PJM and the MMU for approval, along with data and documentation. Valid exceptions must be based on physical operational or contractual limits.[54]

There are no defined consequences for real-time exceptions for units that change their parameters but do not meet the requirements in the tariff. Units that override their turn down ratio (economic maximum divided by economic minimum) either use PJM's fixed gen flag or simply increase their hourly economic minimum.[55] The turn down ratio has a defined parameter limit, but the limit can be evaded by the use of the fixed gen flag. These resources override their output limit parameters with no consequence.

The MMU has proposed that such a unit should not be paid a portion of its capacity market revenues, the daily value for each day, if it fails to include its defined parameter values in its offer (by either using the fixed gen option or increasing their economic minimum). The MMU recommends that PJM require generators to request temporary parameter exceptions for the use of the fixed gen flag. The request process requires generators to demonstrate that the request is based on a physical and actual constraint.

Consistent with the no excuses approach of the capacity performance paradigm and consistent with long term incentives for flexibility, resources that operate with a denied temporary parameter limit exception should not be paid the corresponding 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 they meet 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.[56]

Generator Flexibility Incentives in the Capacity Market

In its June 9, 2015, order on capacity performance, the Commission determined that capacity performance resources should be able to submit operating parameters to the market based not just on the resource physical constraints, but also based on other constraints, such as contractual limits.[57] The order primarily addressed limits imposed by natural gas pipelines. The Commission directed PJM to revise its tariff 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.[58]

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 mitigating the performance risk. The June 9th Order's determination on parameters is not consistent with that goal. By permitting generation owners

54 *See* OA Schedule 1 § 6.6(i) and PJM Manual 11, Section 2.3.4.3.
55 PJM Markets Gateway User Guide, Section 5.8: Self-schedule a Generating Unit and Ignore PJM Dispatch Instruction at 54, Section 14.3 Submit Revised MW Operating Limits at 138 and Section 14.4 Revise the Status of a Generating Unit at 139 <https://www.pjm.com/~/media/etools/markets-gateway/markets-gateway-user-guide.ashx>.
56 *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>.
57 See 151 FERC ¶ 61,208 at P 437 (2015).
58 *Id.* at P 440.

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 and the option to choose from a range of gas pipeline tariff provisions, unlike generating unit operational limits, are a function of the interests and incentives of the generators making the choices. 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 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.

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. The frequency of 24 hour minimum run time requests increased after Winter Storm Elliott in December 2022. Table 3-20 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 2025, there were 93 units in PJM with a total installed capacity of 11,137 MW that requested a 24 hour minimum run time on their parameter limited schedules based on pipeline restrictions.

Table 3-20 Units with 24 hour minimum run times due to gas pipeline restrictions: January 2018 through September 2025

Year	Number of Units With 24 Hour Minimum Run Time Exceptions	Installed Capacity (MW) With 24 Hour Minimun Run Time Exceptions
2018	25	3,627
2019	37	5,616
2020	13	3,873
2021	61	7,514
2022	81	10,019
2023	75	9,824
2024	79	10,476
2025	93	11,137

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 3-66.) 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.

In the first nine months of 2025, PJM paid $147.7 million in day ahead uplift to gas fired units with a 24 hour minimum run time, primarily during the 2025 Polar Vortex. PJM paid an additional $30.9 million in balancing uplift for real-time commitments of units with a 24 hour minimum run time in the first nine months of 2025, with $15.0 million paid to units during the 2025 Polar Vortex.

After observing the misuse of and the failure to use temporary exceptions during Winter Storm Elliott, on September 8, 2023, PJM and the MMU posted guidelines for the correct use of temporary exceptions for pipeline related restrictions. The guidelines detail exactly how units should use temporary exceptions to reflect pipeline restrictions in units' minimum run time, notification time and turn down ratio parameters.[59] During Winter Storm Elliott (December 22-24, 2022), 71 units on average (totaling 8,791 MW) requested temporary exceptions due to pipeline restrictions. During Winter Storm Gerri (January 16-18, 2024), 96 units on average (totaling 13,462 MW) requested temporary exceptions due to pipeline restrictions. During the 2025 Polar Vortex (January 18-23, 2025) 115 units on average (totaling 17,635 MW) requested exceptions due to pipeline restrictions.

The MMU recognizes that pipeline restrictions must be reflected in units' operating parameters in order for PJM to properly schedule and manage the system but it is important to prevent abuse through the submission of inflexible parameters not based on actual constraints. 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 may 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.[60] Up to congestion transactions may be submitted between any two aggregates on a list of 46 aggregates eligible for up to congestion transaction bidding.[61] 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 3-20 shows an example of 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 2025.

59 *See* "Temporary Operating Parameter Limit (PLS) Exceptions due to Pipeline Restrictions" PJM and MMU memorandum to PJM Market Participants (September 8, 2023) <https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Temporary_Operating_Parameter_Limit_(PLS)_Exceptions_due_to_Pipeline_Restrictions_20230908.pdf>.

60 See 162 FERC ¶ 61,139 (2018), *reh'g denied*, 164 FERC ¶ 61,170 (2018).

61 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>.

Figure 3-20 Day-ahead aggregate supply curves: 2025 example day

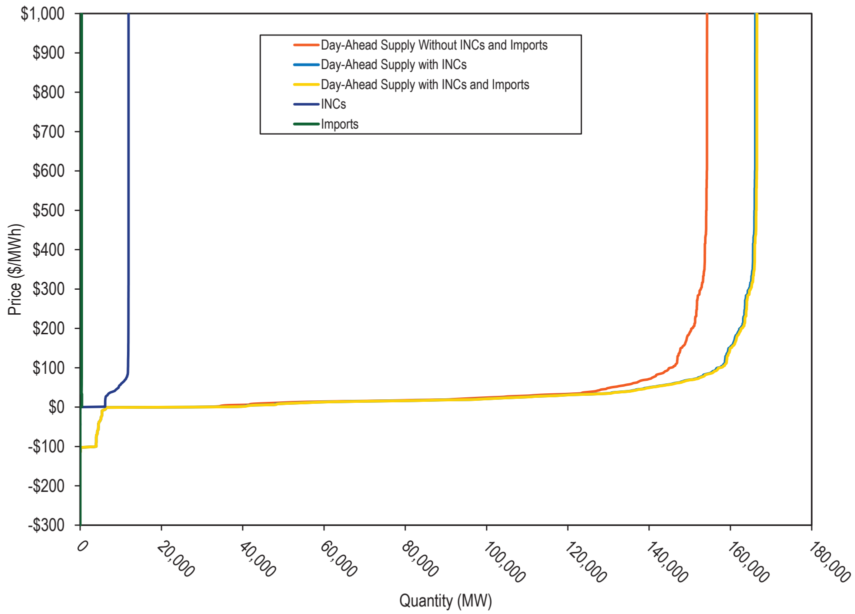


Table 3-21 shows the hourly average number of cleared and submitted increment offers and decrement bids by month in 2024 and the first nine months of 2025.[62] The hourly average submitted increment offer MW increased by 4.6 percent and cleared increment MW increased by 8.4 percent in the first nine months of 2025 compared to the first nine months of 2024. The hourly average submitted decrement bid MW increased by 17.7 percent and cleared decrement MW increased by 2.6 percent in the first nine months of 2025 compared to the first nine months of 2024.

Table 3-21 Average hourly number of cleared and submitted INCs and DECs by month: January 2024 through September 2025

		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
2024	Jan	4,660	10,515	402	1,499	5,161	11,668	287	1,113
2024	Feb	5,716	12,429	487	1,789	5,063	10,952	275	1,039
2024	Mar	6,040	12,378	426	1,422	5,802	12,563	334	1,202
2024	Apr	5,848	11,972	480	1,248	5,055	11,940	385	1,204
2024	May	5,634	11,961	452	1,241	5,213	13,453	397	1,445
2024	Jun	4,627	10,503	420	1,176	5,468	13,163	362	1,290
2024	Jul	4,042	10,177	392	1,177	5,360	13,376	421	1,416
2024	Aug	3,802	9,767	373	1,107	6,269	13,946	496	1,432
2024	Sep	3,640	9,507	396	1,225	5,588	13,517	467	1,646
2024	Oct	5,091	11,262	509	1,530	4,351	13,985	424	1,946
2024	Nov	5,136	11,621	437	1,461	4,491	13,307	414	1,731
2024	Dec	5,570	12,681	479	1,705	5,686	15,190	493	2,037
2024	Annual	4,982	11,228	438	1,381	5,295	13,101	397	1,461
2025	Jan	6,024	12,413	535	1,821	5,068	14,037	420	1,914
2025	Feb	6,207	12,420	566	1,868	5,152	14,703	444	2,089
2025	Mar	6,239	12,836	603	1,920	5,177	15,163	464	2,262
2025	Apr	6,142	12,604	584	1,679	4,343	14,247	486	2,124
2025	May	5,007	10,837	543	1,480	4,947	13,199	452	1,703
2025	Jun	4,130	10,385	466	1,435	6,310	16,189	570	2,171
2025	Jul	4,609	10,299	481	1,366	6,414	15,731	541	2,262
2025	Aug	4,694	11,329	472	1,481	6,253	14,633	502	1,821
2025	Sep	4,679	10,619	536	1,653	6,606	17,145	591	2,464
2025	Jan-Sep	5,297	11,521	531	1,632	5,589	14,999	497	2,088

Table 3-22 shows the average hourly number of up to congestion transactions and the average hourly MW by month in 2024 and the first nine months of 2025. The hourly average submitted up to congestion bid MW decreased by 1.4 percent and cleared up to congestion bid MW decreased by 10.1 percent in the first nine months of 2025 compared to the first nine months of 2024.

62 Table 3-21 uses cleared day-ahead market data while final settlements data is used elsewhere in this report.

Table 3-22 Average hourly cleared and submitted up to congestion bids by month: January 2024 through September 2025

		Up to Congestion			
Year	Month	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2024	Jan	13,905	35,217	787	1,667
2024	Feb	12,773	30,008	563	1,307
2024	Mar	14,401	37,663	600	1,432
2024	Apr	10,922	35,180	535	1,443
2024	May	9,073	29,896	627	1,567
2024	Jun	9,810	26,251	638	1,365
2024	Jul	8,721	27,022	757	1,532
2024	Aug	9,016	27,970	841	1,575
2024	Sep	10,489	31,088	782	1,631
2024	Oct	10,684	33,321	670	1,611
2024	Nov	9,093	30,131	533	1,438
2024	Dec	10,442	32,473	748	1,790
2024	Annual	10,774	31,366	675	1,532
2025	Jan	10,955	34,709	911	2,194
2025	Feb	12,000	34,801	798	2,034
2025	Mar	10,512	34,843	741	2,095
2025	Apr	8,415	29,420	610	1,999
2025	May	7,851	21,973	503	1,574
2025	Jun	11,046	32,384	791	2,071
2025	Jul	9,595	29,536	913	2,229
2025	Aug	9,019	25,911	669	1,802
2025	Sep	9,844	33,392	741	2,383
2025	Jan-Sep	9,894	30,719	742	2,041

Table 3-23 shows the average hourly number of day-ahead import and export transactions and the average hourly MW in 2024 and the first nine months of 2025.[63] In the first nine months of 2025, the average hourly submitted import transaction MW decreased by 10.9 percent and the average hourly cleared import transaction MW decreased by 11.4 percent compared to the first nine months of 2024. In the first nine months of 2025, the average hourly submitted export transaction MW increased by 16.4 percent and the average hourly cleared export transaction MW increased by 15.9 percent compared to the first nine months of 2024.

Table 3-23 Hourly average day-ahead number of cleared and submitted import and export transactions by month: January 2024 through September 2025

		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
2024	Jan	322	394	4	5	4,561	4,590	33	34
2024	Feb	353	411	4	4	4,132	4,146	31	31
2024	Mar	345	375	5	5	3,912	3,917	34	35
2024	Apr	250	277	4	4	3,200	3,235	23	23
2024	May	400	422	5	5	2,812	2,828	21	21
2024	Jun	179	196	3	3	4,585	4,599	35	36
2024	Jul	304	344	4	5	3,820	3,850	27	28
2024	Aug	295	335	4	5	4,112	4,160	28	29
2024	Sep	258	275	4	5	3,387	3,474	25	26
2024	Oct	731	783	9	9	2,662	2,723	23	24
2024	Nov	477	650	6	8	2,695	2,716	26	26
2024	Dec	504	680	5	6	3,987	4,257	36	37
2024	Annual	375	434	5	5	3,655	3,708	29	29
2025	Jan	199	330	3	4	4,392	4,575	37	38
2025	Feb	355	403	5	6	4,948	4,992	41	42
2025	Mar	192	192	3	3	4,430	4,485	39	40
2025	Apr	366	384	5	6	3,789	3,821	26	27
2025	May	278	294	4	5	3,752	3,761	28	28
2025	Jun	193	215	3	4	4,426	4,467	33	34
2025	Jul	286	313	5	5	4,787	4,827	34	34
2025	Aug	213	242	4	5	5,232	5,268	39	40
2025	Sep	324	338	6	6	4,267	4,308	30	31
2025	Jan-Sep	267	300	4	5	4,445	4,499	34	35

Figure 3-21 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month from 2005 through September 2025. Cleared volumes were greater in 2023 than any year since 2020, when uplift charges for up to congestion transactions took effect on November 1, 2020. The monthly MW volume of UTC bids in April 2023 was at its highest level since 2017, but decreased significantly beginning May 2023 and has remained stable beginning August 2023 through September 2025.

63 Table 3-23 uses cleared day-ahead market data, while final settlements data is used elsewhere in this report.

Figure 3-21 Monthly bid and cleared INCs, DECs and UTCs (GWh): January 2005 through September 2025

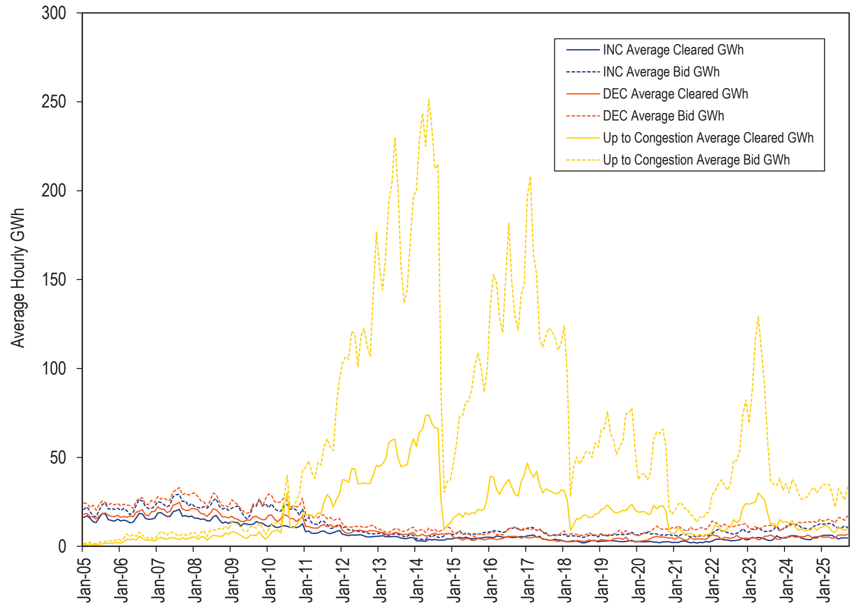


Figure 3-22 Daily bid and cleared INCs, DECs, and UTCs (GWh): January 2024 through September 2025

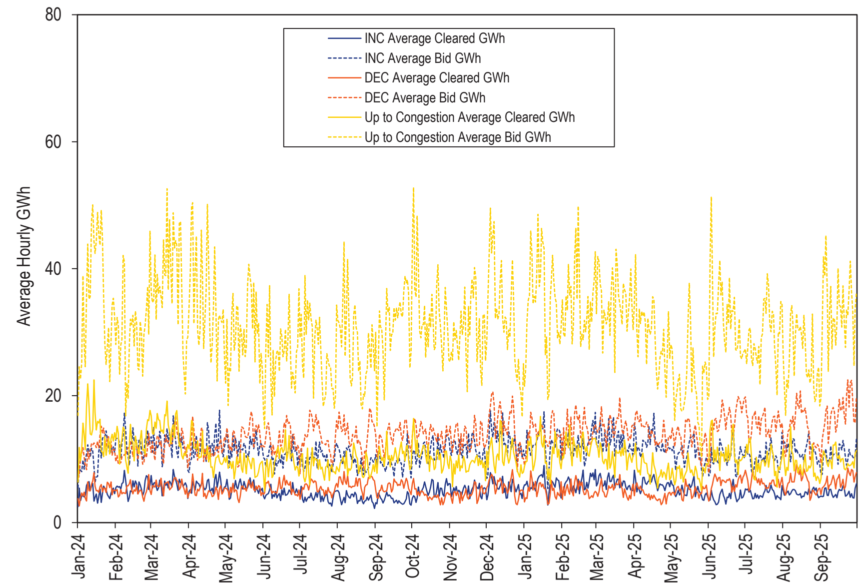


Figure 3-22 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 2024 through September 2025.

In order to evaluate the ownership of virtual bids, the MMU categorizes all participants making virtual bids in PJM as either physical or financial at an account level.[64] Physical entities are defined as individual accounts in PJM's settlement systems that take physical positions in PJM markets and typically include utilities and customers. Financial entities are defined as individual accounts in PJM's settlement systems that take financial positions in PJM markets and typically include banks and trading firms. 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 cleared MWh of INCs and DECs in the first nine months of 2025 increased to 97.2 percent from 95.3 percent in the nine months of 2024.

64 The MMU modified the method for categorizing participants as physical and financial participants. See the explanation in the *2025 Quarterly State of the Market Report for PJM: January through March*, Section 13: Financial Transmission Rights at Market Structure (May 8, 2025).

Table 3-24 shows, in the first nine months of 2024 and 2025, the total increment offers and decrement bids and cleared MW by organization type.

Table 3-24 INC and DEC bids and cleared MWh by organization type (MWh): January through September, 2024 and 2025

	2024 (Jan-Sep)				2025 (Jan-Sep)			
Category	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	152,545,517	97.7%	64,764,225	95.3%	171,154,662	98.5%	69,297,250	97.2%
Physical	3,670,941	2.3%	3,165,336	4.7%	2,575,568	1.5%	2,012,997	2.8%
Total	156,216,457	100.0%	67,929,560	100.0%	173,730,230	100.0%	71,310,247	100.0%

Table 3-25 shows the total up to congestion bid and cleared MWh by organization type in the first nine months of 2024 and 2025. Up to congestion bids submitted by financial entities decreased in the first nine months of 2025 compared to the first nine months of 2024 from 200.3 million MWh to 196.2 million MWh, while up to congestion bids submitted by physical entities increased from 2.6 million MWh to 3.1 million MWh. Financial entities submitted 97.5 percent of all up to congestion bids, down from 97.8 percent, and cleared 95.2 percent of all up to congestion bids, down from 96.4 percent. In the first nine months of 2025, almost all up to congestion trading activity was by financial participants.

Table 3-25 Up to congestion transactions by organization type (MWh): January through September, 2024 and 2025

Year	Category	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent
	Financial	200,264,451	97.8%	69,773,828	96.4%
2024 (Jan-Sep)	Physical	4,576,619	2.2%	2,587,200	3.6%
	Total	204,841,069	100.0%	72,361,028	100.0%
	Financial	196,170,605	97.5%	61,675,259	95.2%
2025 (Jan-Sep)	Physical	5,069,592	2.5%	3,139,560	4.8%
	Total	201,240,197	100.0%	64,814,819	100.0%
	Financial	(4,093,846)	(2.0%)	(8,098,569)	(11.6%)
(2025 minus 2024)	Physical	492,973	10.8%	552,361	21.3%
	Difference	(3,600,873)	(1.8%)	(7,546,209)	(10.4%)

Table 3-26 shows the total import and export transactions by organization type in the first nine months of 2024 and 2025.

Table 3-26 Import and export transactions by organization type (MWh): January through September, 2024 and 2025

		2024 (Jan-Sep)		2025 (Jan-Sep)	
	Category	Total Import and Export MWh	Percent	Total Import and Export MWh	Percent
Day-Ahead	Financial	13,827,436	51.0%	16,180,293	52.5%
	Physical	13,259,314	49.0%	14,622,339	47.5%
	Total	27,086,750	100.0%	30,802,631	100.0%
Real-Time	Financial	27,290,607	55.6%	31,378,872	57.6%
	Physical	21,824,068	44.4%	23,092,413	42.4%
	Total	49,114,676	100.0%	54,471,285	100.0%

Table 3-27 shows the top 10 locations by total cleared INC and DEC MWh in the first nine months of 2024 and 2025. The top 10 locations included four hubs, four interface pricing points, and two residual metered load aggregates. For generator pnodes not included in the top 10 by the sum of INCs and DECs, DAVISBES25 KV DB10 cleared the most INC volume of 486,147 MWh and REMNTNCT18 KV GT1 with the most DEC volume of 348,822 MWh in the first nine months of 2025.

Table 3-27 Virtual offers and bids by top 10 locations (MWh): January through September, 2024 and 2025

2024 (Jan-Sep)					2025 (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
WESTERN HUB	HUB	2,690,189	1,569,874	4,260,064	MISO	INTERFACE	365,157	4,662,100	5,027,257
MISO	INTERFACE	109,155	3,814,561	3,923,716	WESTERN HUB	HUB	2,512,398	1,673,987	4,186,385
SOUTH	INTERFACE	2,459,609	425,520	2,885,130	SOUTH	INTERFACE	2,943,317	626,681	3,569,997
N ILLINOIS HUB	HUB	2,052,540	618,932	2,671,473	N ILLINOIS HUB	HUB	1,637,986	745,694	2,383,681
NYIS	INTERFACE	484,413	1,521,984	2,006,397	DOM_RESID_AGG	RESIDUAL METERED EDC	383,270	1,419,758	1,803,028
AEP-DAYTON HUB	HUB	842,250	939,372	1,781,622	NYIS	INTERFACE	553,310	1,223,893	1,777,203
DOM_RESID_AGG	RESIDUAL METERED EDC	192,190	1,226,010	1,418,200	AEP-DAYTON HUB	HUB	508,545	778,574	1,287,119
LINDENVFT	INTERFACE	22,936	1,233,117	1,256,053	LINDENVFT	INTERFACE	42,895	1,212,347	1,255,242
BGE_RESID_AGG	RESIDUAL METERED EDC	336,506	855,626	1,192,132	BGE_RESID_AGG	RESIDUAL METERED EDC	529,897	687,364	1,217,261
EASTERN HUB	HUB	294,056	637,935	931,992	CHICAGO HUB	HUB	572,186	544,995	1,117,180
Top ten total		9,483,844	12,842,932	22,326,777			10,048,962	13,575,392	23,624,354
PJM total		32,124,357	35,805,204	67,929,561			34,699,620	36,610,626	71,310,247
Top ten total as percent of PJM total		29.5%	35.9%	32.9%			29.0%	37.1%	33.1%

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 2024 and 2025. Total profits for up to congestion transactions in the first nine months of 2025 were $50.7 million, a 50.4 million increase compared to profits of $0.2 million in the first nine months of 2024.[65] The UTCs from DOMINION HUB to DOM_RESID_AGG constituted 10.7 percent of all UTC cleared volume in the first nine months of 2025, yielding a profit of $19.3 million.

Table 3-28 Cleared up to congestion bids by top 10 source and sink pairs (MWh): January through September, 2024 and 2025[66]

2024 (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	8,177,178	$4,105,787	($4,654,145)	($3,885,209)
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	3,764,134	($208,806)	$3,075,769	$1,723,175
CHICAGO GEN HUB	HUB	CHICAGO HUB	HUB	3,524,261	($2,508,850)	$5,395,283	$1,385,851
AEP GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	1,999,891	($371,365)	$1,316,711	$276,483
CHICAGO GEN HUB	HUB	OHIO HUB	HUB	1,759,904	$1,204,365	$587,718	$1,148,776
CHICAGO GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	1,677,342	$2,861,186	($539,374)	$1,558,855
CHICAGO GEN HUB	HUB	MISO	INTERFACE	1,470,580	($582,713)	$266,317	($771,853)
CHICAGO GEN HUB	HUB	DEOK_RESID_AGG	AGGREGATE	1,183,341	$1,235,394	($261,925)	$466,324
CHICAGO GEN HUB	HUB	N ILLINOIS HUB	HUB	969,451	($2,774,095)	$4,060,549	$860,502
UGI_RESID_AGG	AGGREGATE	NYIS	INTERFACE	889,649	($799,717)	$1,147,864	($5,925)
Top ten total				25,415,732	$2,161,186	$10,394,768	$2,756,980
PJM total				72,361,028	$20,362,164	$10,501,009	$228,499
Top ten total as percent of PJM total				35.1%	10.6%	99.0%	1206.6%
2025 (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	6,934,245	$3,226,115	$19,595,592	$19,334,980
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	2,713,485	$3,830,128	($1,113,183)	$874,399
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	1,190,902	($163,051)	$2,321,086	$1,352,275
CHICAGO GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	1,157,365	$837,321	$197,409	$509,159
CHICAGO GEN HUB	HUB	CHICAGO HUB	HUB	1,131,621	($1,165,219)	$1,964,343	$44,367
AEP GEN HUB	HUB	AEPAPCO_RESID_AGG	AGGREGATE	707,058	$4,656,936	($1,321,860)	$2,190,725
CHICAGO GEN HUB	HUB	COMED_RESID_AGG	AGGREGATE	685,163	($374,408)	$947,193	$10,207
ATSI GEN HUB	HUB	DUQ_RESID_AGG	AGGREGATE	664,978	$1,352,792	($238,428)	$585,908
CHICAGO GEN HUB	HUB	OHIO HUB	HUB	643,910	$17,870	$310,263	($20,645)
CHICAGO GEN HUB	HUB	N ILLINOIS HUB	HUB	630,880	($111,352)	$478,255	($9,830)
Top ten total				16,459,605	$12,107,132	$23,140,671	$24,871,544
PJM total				64,814,819	$34,925,370	$62,087,104	$50,664,308
Top ten total as percent of PJM total				25.4%	34.7%	37.3%	49.1%

65 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.

66 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 distinct source-sink pairs that were offered and cleared each month from January 2024 through September 2025. The average number of submitted source-sink pairs per day increased from 1,212 source-sink pairs submitted in the first nine months of 2024 to 1,507 in the first nine months of 2025. The average number of cleared source-sink pairs per day increased from 907 in the first nine months of 2024 to 1,204 per day in the first nine months of 2025.

Table 3-29 Number of offered and cleared UTC source and sink pairs: January 2024 through September 2025

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2024	Jan	1,298	1,521	1,047	1,347
2024	Feb	1,166	1,364	810	991
2024	Mar	1,062	1,333	745	1,014
2024	Apr	1,095	1,414	788	1,021
2024	May	1,241	1,560	934	1,325
2024	Jun	1,194	1,528	969	1,377
2024	Jul	1,308	1,520	1,165	1,317
2024	Aug	1,265	1,572	1,129	1,486
2024	Sep	1,271	1,462	1,130	1,319
2024	Oct	1,363	1,563	1,176	1,363
2024	Nov	1,323	1,485	1,039	1,294
2024	Dec	1,418	1,729	1,167	1,486
2024	Annual	1,250	1,504	1,008	1,278
2025	Jan	1,454	1,641	1,222	1,490
2025	Feb	1,411	1,617	1,174	1,399
2025	Mar	1,523	1,844	1,278	1,641
2025	Apr	1,477	1,718	1,123	1,428
2025	May	1,360	1,597	938	1,325
2025	Jun	1,521	1,847	1,208	1,622
2025	Jul	1,680	1,852	1,380	1,654
2025	Aug	1,572	1,836	1,249	1,554
2025	Sep	1,554	1,766	1,257	1,497
2025	Annual	1,501	1,743	1,203	1,512

Table 3-30 and Figure 3-23 show total cleared up to congestion transactions and the share of the top 10 up to congestion paths by transaction type (import, export, wheel, or internal) in the first nine months of 2024 and 2025. Total cleared up to congestion transactions decreased by 10.4 percent from 72.3 million MWh in the first nine months of 2024 to 64.8 million MWh in the first nine months of 2025. Internal up to congestion transactions in the first nine months of 2025 were 85.0 percent of all up to congestion transactions, an increase from 83.5 percent in the first nine months of 2024.

Table 3-30 Cleared up to congestion transactions and share of top 10 paths by type (MW): January through September, 2024 and 2025

	2024 (Jan-Sep)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	2,429,265	3,664,188	1,504,309	24,622,166	32,219,929
PJM total (MW)	4,617,138	5,670,164	1,624,775	60,448,950	72,361,028
Top ten total as percent of PJM total	52.6%	64.6%	92.6%	40.7%	44.5%
PJM total as percent of all up to congestion transactions	6.4%	7.8%	2.2%	83.5%	100.0%
	2025 (Jan-Sep)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	2,714,664	1,563,471	886,913	16,459,605	21,624,653
PJM total (MW)	4,952,707	3,753,697	1,006,894	55,101,521	64,814,819
Top ten total as percent of PJM total	54.8%	41.7%	88.1%	29.9%	33.4%
PJM total as percent of all up to congestion transactions	7.6%	5.8%	1.6%	85.0%	100.0%

Figure 3-23 shows the total volume of import, export, wheel, and internal up to congestion transactions by month from January 2005 through June 2025. 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.[67] 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.[68] 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.[69] In 2022 and the first six months of 2023, the volume of cleared UTCs increased significantly, primarily internal transactions. The volume of cleared UTCs decreased consistently from July 2023 through September 2025.

67 See 162 FERC ¶ 61,139 (2018), *reh'g denied*, 164 FERC ¶ 61,170 (2018).

68 *Id.*

69 See 172 FERC ¶ 61,046 (2020).

Figure 3-23 Monthly cleared up to congestion transactions by type (GWh): January 2005 through September 2025

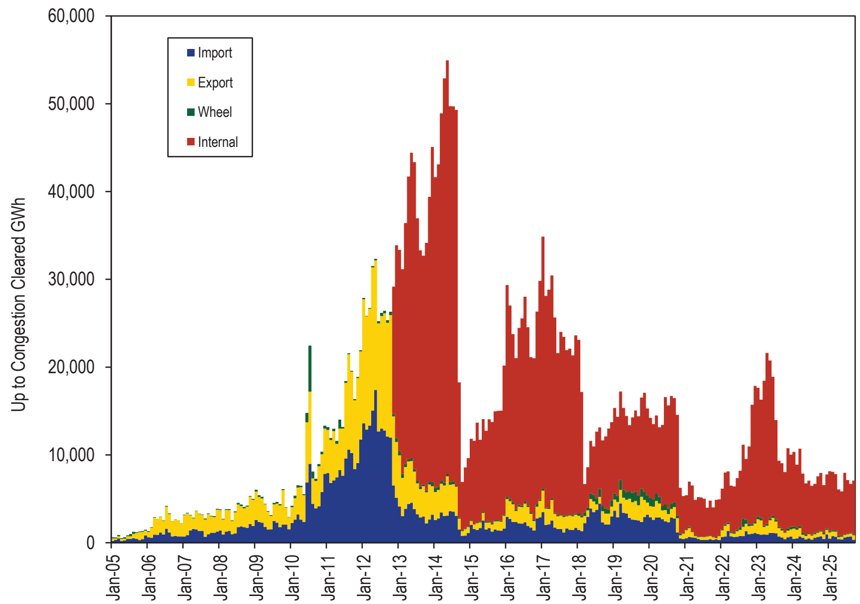


Figure 3-24 Daily cleared up to congestion transaction by type (GWh): January 2024 through September 2025

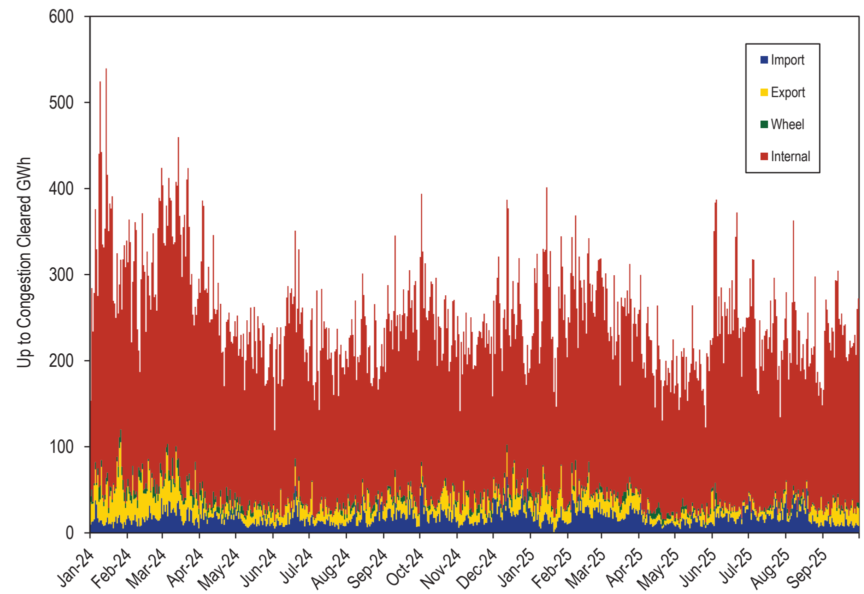


Figure 3-24 shows the daily cleared up to congestion GWh by transaction type from January 1, 2024, through September 30, 2025. In the first nine months of 2025, the total cleared GWh of import, export, and internal up to congestion transactions remained relatively unchanged compared to 2024.

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.[70]

A key assumption underlying the February 2018 order was 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

70 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."

of prices over a large number of buses at aggregate nodes.[71] 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 models since the February 2018 order.

The assumption that modeling differences are averaged out over the multiple individual nodes included in aggregate nodes does not hold for multiple aggregate 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 the line ratings on constraints are violated and transmission penalty factors are applied in the real-time energy market. This occurs both when line ratings are actually violated and when PJM operators reduce the line ratings in SCED. 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 significant, even when averaged over an aggregate node, and may persist for days or weeks. Virtual traders can often identify and profit from price spreads 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.

71 See 162 FERC ¶ 61,139 at PP 35–36 ("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.").

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 shortage pricing, the creation of closed loop interfaces 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 transmission constraint penalty factors, and committing reserves beyond the requirement, or change price formation through fast start pricing.

The real-time average LMP in the first nine months of 2025 increased $14.57 per MWh, or 46.2 percent, from the first nine months of 2024, from $31.50 per MWh to $46.05 per MWh. The real-time load-weighted average LMP in the first nine months of 2025 increased $16.20 per MWh, or 47.2 percent from the first nine months of 2024, from $34.31 per MWh to $50.51 per MWh.

The costs of fuel, emissions, and consumables, fundamental components of the real-time load-weighted average LMP, increased $9.85 per MWh from $19.75 per MWh in the first nine months of 2024 to $29.59 per MWh in the first nine months of 2025, or 60.8 percent of the increase in real-time load-weighted average LMP.

The day-ahead average LMP for the first nine months of 2025 increased $14.60 per MWh, or 47.0 percent from the first nine months of 2024, from $31.09 per MWh to $45.69 per MWh. The day-ahead load-weighted average LMP for the first nine months of 2025 increased $16.03 or 47.4 percent from the first nine months of 2024, from $33.85 per MWh to $49.88 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.[72] 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, to ensure 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.[73]

LMP may, at times, be set by administratively defined transmission constraint penalty factors, which equal a default level of $30,000 per MWh in the day-ahead market dispatch run 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 constraint penalty factors. The shadow price directly affects the LMP. Transmission constraint penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing. However, PJM operator interventions to reduce the control limits on transmission constraint line ratings used in the market clearing unnecessarily trigger transmission constraint penalty factors and significantly increase prices. A competitive market does not require that prices increase when PJM artificially triggers transmission constraint penalty factors.

72 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.

73 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).

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 is based on an incorrect LMP calculation called the pricing run. The pricing run LMP (PLMP) is 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 less than or equal to one hour; minimum run time less than or equal to one hour; and can set price only when 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. On June 24, PJM capped the energy LMP in the pricing run at $3,700 per MWh for two five minute intervals in the hour beginning at 1800 and one five minute interval in the hour beginning at 1900. This system marginal price (SMP) capping process has not been reviewed by FERC or included in the PJM Operating Agreement.

DLMP and PLMP

Table 3-31 shows the day-ahead and real-time monthly load-weighted average PLMP and DLMP in 2024 and the first nine months of 2025.

The real-time load-weighted average PLMP was $50.51 per MWh for the first nine months of 2025, which is 9.0 percent, $4.17 per MWh, higher than the real-time load-weighted average DLMP of $46.34 per MWh.

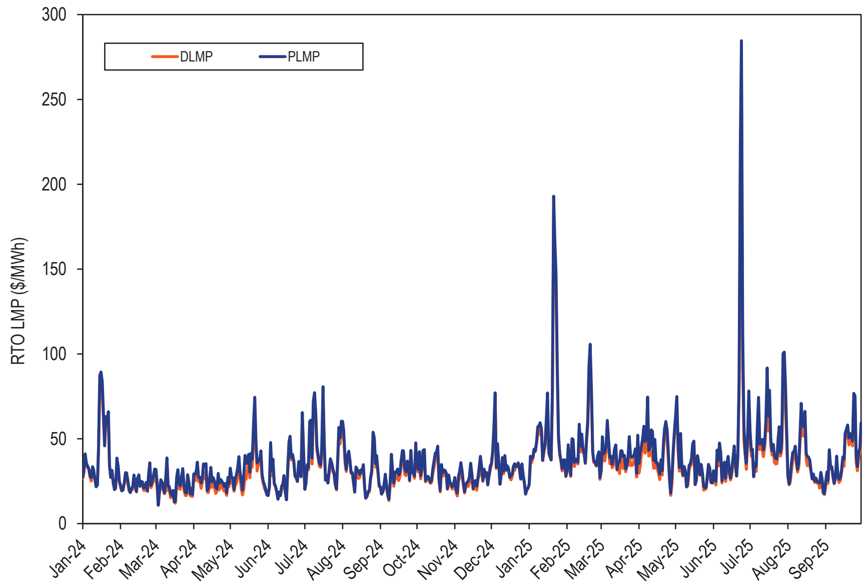
The day-ahead load-weighted average PLMP was $49.88 per MWh for the first nine months of 2025, which is 0.1 percent, $0.07 per MWh, higher than the day-ahead load-weighted average DLMP of $49.81 per MWh.

Table 3-31 Day-ahead and real-time load-weighted average DLMP and PLMP: 2024 through September 2025

		Day-Ahead Load-Weighted Average				Real-Time Load-Weighted Average			
Year	Month	DLMP	PLMP	Difference	Percent Difference	DLMP	PLMP	Difference	Percent Difference
2024	Jan	$48.45	$48.65	$0.20	0.4%	$40.82	$42.78	$1.95	4.8%
2024	Feb	$23.67	$23.70	$0.03	0.1%	$23.20	$24.86	$1.66	7.2%
2024	Mar	$21.89	$21.93	$0.04	0.2%	$20.30	$23.15	$2.85	14.0%
2024	Apr	$26.73	$26.75	$0.02	0.1%	$23.29	$27.17	$3.87	16.6%
2024	May	$32.92	$32.90	($0.02)	(0.1%)	$31.70	$36.16	$4.46	14.1%
2024	Jun	$32.59	$32.62	$0.03	0.1%	$31.95	$33.35	$1.40	4.4%
2024	Jul	$44.51	$44.69	$0.18	0.4%	$44.12	$47.17	$3.04	6.9%
2024	Aug	$36.34	$36.31	($0.03)	(0.1%)	$34.37	$36.29	$1.92	5.6%
2024	Sep	$30.63	$30.77	$0.14	0.4%	$29.32	$31.81	$2.48	8.5%
2024	Oct	$33.18	$33.26	$0.08	0.2%	$29.85	$31.87	$2.02	6.8%
2024	Nov	$29.78	$29.82	$0.04	0.1%	$25.70	$28.26	$2.55	9.9%
2024	Dec	$36.98	$37.05	$0.06	0.2%	$33.62	$34.98	$1.36	4.0%
2024	Jan - Sep	$33.78	$33.85	$0.07	0.2%	$31.73	$34.31	$2.58	8.1%
2024		$33.72	$33.79	$0.07	0.2%	$31.31	$33.74	$2.43	7.7%
2025	Jan	$67.53	$67.74	$0.21	0.3%	$59.93	$62.87	$2.94	4.9%
2025	Feb	$48.85	$49.02	$0.16	0.3%	$46.27	$48.90	$2.62	5.7%
2025	Mar	$40.76	$40.74	($0.03)	(0.1%)	$37.82	$42.11	$4.30	11.4%
2025	Apr	$44.36	$44.35	($0.01)	(0.0%)	$40.07	$45.42	$5.35	13.4%
2025	May	$37.56	$37.40	($0.16)	(0.4%)	$33.98	$36.34	$2.36	6.9%
2025	Jun	$53.01	$53.14	$0.13	0.2%	$62.53	$68.13	$5.60	9.0%
2025	Jul	$66.56	$66.76	$0.20	0.3%	$52.41	$59.38	$6.97	13.3%
2025	Aug	$39.24	$39.27	$0.03	0.1%	$35.97	$39.52	$3.55	9.9%
2025	Sep	$41.26	$41.24	($0.02)	(0.0%)	$40.49	$43.71	$3.22	7.9%
2025	Jan - Sep	$49.81	$49.88	$0.07	0.1%	$46.34	$50.51	$4.17	9.0%

Figure 3-25 shows the real-time daily average DLMP and PLMP in 2024 through September 2025.

Figure 3-25 Real-time daily average DLMP and PLMP: 2024 through September 2025



Fast start pricing created a larger difference between DLMP and PLMP in real time than in day ahead. Figure 3-26 shows the hourly difference between DLMP and PLMP in day-ahead and real-time for the first nine months of 2025.

The large differences between DA DLMP and PLMP on January 20, 2025, were caused by the higher transmission constraint penalty factors in the day-ahead dispatch run. In the dispatch run, the penalty factor was set at $30,000, while in the pricing run the penalty factor was set at $2,000.

The large differences between RT DLMP and PLMP on June 24, 2025, occurred when the energy component of the pricing run LMP was administratively set at $3,500 per MWh.

Figure 3-26 Hourly difference between DLMP and PLMP for day-ahead and real-time: January through September, 2025

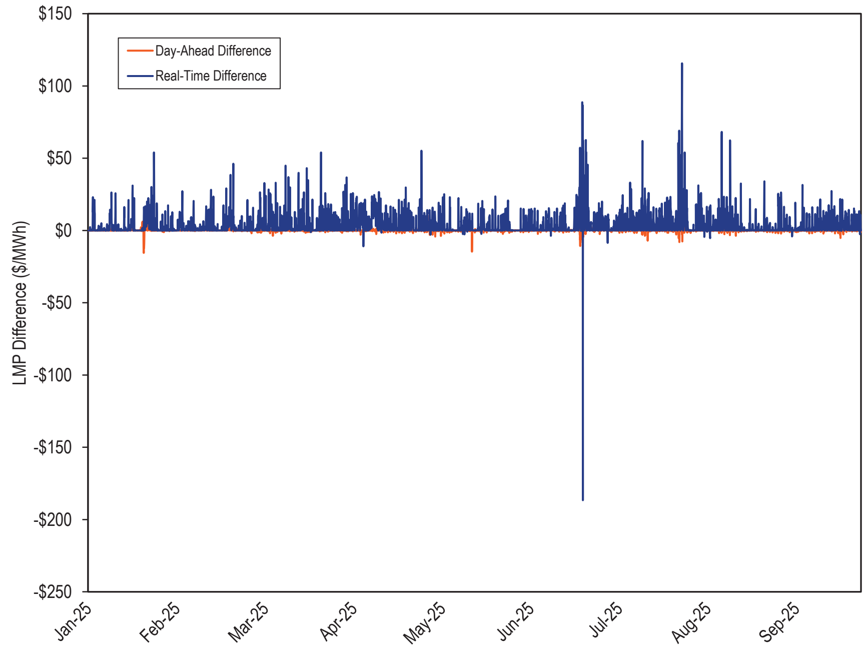


Figure 3-27 shows the hourly average load and LMP difference by hour of the day for the first nine months of 2025. The PLMP minus DLMP difference is largest at the times of the morning and evening peak loads.

Figure 3-27 Hourly average load and LMP difference: January through September, 2025

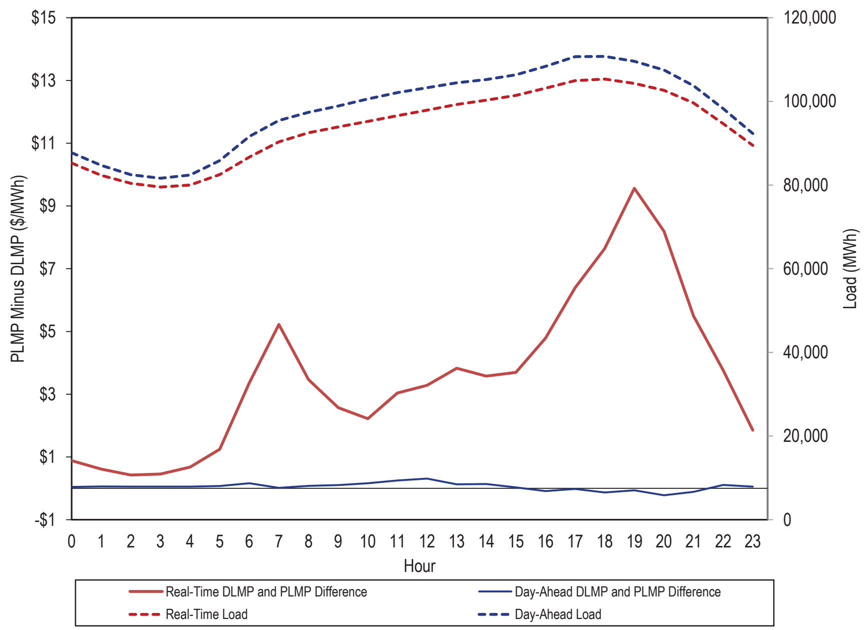


Table 3-32 shows the percent of total marginal units that are fast start units by unit type in 2024 and the first nine months of 2025. While wind units are defined as fast start units, a wind unit on the margin does not result in a higher PLMP than DLMP when the unit has no commitment costs.

Table 3-32 Fast start units as a percent of real-time marginal units: 2024 through September 2025

		Dispatch Run				Pricing Run			
Year	Month	CT	Diesel	Wind	All Fast Start Units	CT	Diesel	Wind	All Fast Start Units
2024	Jan	0.7%	0.6%	0.0%	1.3%	3.5%	1.1%	0.0%	4.7%
2024	Feb	0.4%	0.1%	0.1%	0.5%	2.2%	0.1%	0.1%	2.4%
2024	Mar	0.7%	0.2%	1.2%	2.1%	4.1%	0.8%	1.3%	6.2%
2024	Apr	1.5%	0.2%	0.2%	1.9%	6.5%	0.7%	0.1%	7.3%
2024	May	0.6%	0.2%	0.1%	1.0%	5.1%	0.6%	0.1%	5.8%
2024	Jun	0.5%	0.3%	0.1%	0.8%	3.5%	0.4%	0.1%	4.0%
2024	Jul	0.8%	0.5%	0.0%	1.4%	7.4%	1.0%	0.0%	8.5%
2024	Aug	0.6%	0.5%	0.0%	1.1%	5.0%	1.0%	0.0%	6.0%
2024	Sep	1.0%	0.1%	0.0%	1.1%	7.1%	0.4%	0.0%	7.6%
2024	Oct	1.2%	0.1%	0.0%	1.3%	6.4%	1.3%	0.0%	7.7%
2024	Nov	1.0%	0.2%	0.0%	1.4%	6.2%	0.6%	0.0%	7.0%
2024	Dec	0.5%	0.2%	0.0%	0.7%	2.2%	0.6%	0.0%	2.9%
2024	Jan - Sep	0.8%	0.3%	0.2%	1.3%	4.9%	0.7%	0.2%	5.8%
2025	Jan	0.8%	0.6%	0.1%	1.5%	4.5%	2.1%	0.1%	6.8%
2025	Feb	1.5%	0.1%	0.4%	2.0%	3.7%	0.6%	0.3%	4.6%
2025	Mar	0.5%	4.5%	0.1%	5.2%	3.4%	5.0%	0.1%	8.6%
2025	Apr	1.9%	1.8%	0.3%	4.1%	7.1%	2.2%	0.3%	9.7%
2025	May	0.6%	0.3%	0.0%	1.0%	3.9%	1.5%	0.0%	5.4%
2025	Jun	1.4%	0.2%	0.0%	1.6%	6.2%	0.8%	0.0%	7.0%
2025	Jul	2.6%	0.6%	0.0%	3.2%	11.2%	1.5%	0.0%	12.8%
2025	Aug	2.2%	0.5%	0.0%	2.7%	7.8%	1.1%	0.0%	8.9%
2025	Sep	1.2%	0.4%	0.0%	1.6%	5.7%	1.2%	0.0%	6.9%
2025	Jan - Sep	1.4%	1.0%	0.1%	2.6%	5.9%	1.8%	0.1%	7.9%

Table 3-33 shows the difference between day-ahead and real-time zonal average DLMP and PLMP for the first nine months of 2025.

Fast start pricing affects some zones more than others. The average increase in real-time prices in BGE was $4.53 per MWh, 8.9 percent, while the average increase in real-time prices in PECO was $2.83 per MWh, 7.8 percent.

Table 3-33 Day-ahead and real-time zonal average DLMP and PLMP (Dollars per MWh): January through September, 2025

	2025 (Jan-Sep)							
	Day-Ahead				Real-Time			
Zone	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
ACEC	$40.68	$40.75	$0.07	0.2%	$37.41	$40.34	$2.93	7.8%
AEP	$44.61	$44.65	$0.05	0.1%	$41.32	$45.00	$3.68	8.9%
APS	$45.47	$45.54	$0.06	0.1%	$42.28	$46.12	$3.84	9.1%
ATSI	$44.61	$44.62	$0.01	0.0%	$40.53	$44.17	$3.63	9.0%
BGE	$54.91	$55.00	$0.09	0.2%	$50.63	$55.16	$4.53	8.9%
COMED	$36.33	$36.40	$0.07	0.2%	$33.22	$36.27	$3.04	9.2%
DAY	$45.19	$45.24	$0.05	0.1%	$41.02	$44.72	$3.70	9.0%
DUKE	$43.78	$43.83	$0.05	0.1%	$39.66	$43.25	$3.60	9.1%
DOM	$57.36	$57.38	$0.02	0.0%	$54.33	$58.40	$4.08	7.5%
DPL	$44.19	$44.29	$0.10	0.2%	$39.61	$43.46	$3.85	9.7%
DUQ	$42.97	$43.01	$0.04	0.1%	$39.56	$43.13	$3.57	9.0%
EKPC	$43.42	$43.48	$0.06	0.1%	$40.30	$43.91	$3.61	9.0%
JCPLC	$40.86	$40.92	$0.07	0.2%	$37.61	$40.59	$2.97	7.9%
MEC	$43.25	$43.31	$0.06	0.1%	$39.39	$42.63	$3.24	8.2%
OVEC	$42.35	$42.39	$0.05	0.1%	$38.26	$41.75	$3.49	9.1%
PECO	$39.64	$39.71	$0.07	0.2%	$36.42	$39.25	$2.83	7.8%
PE	$46.90	$46.92	$0.03	0.1%	$42.87	$46.44	$3.57	8.3%
PEPCO	$54.04	$54.11	$0.07	0.1%	$49.94	$54.19	$4.26	8.5%
PPL	$39.12	$39.18	$0.07	0.2%	$35.81	$38.82	$3.01	8.4%
PSEG	$41.03	$41.11	$0.07	0.2%	$38.39	$41.43	$3.04	7.9%
REC	$44.75	$44.83	$0.07	0.2%	$41.80	$45.05	$3.25	7.8%

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 2025.

The average increase in real-time prices for the DOMINION HUB was $3.94 per MWh, 8.6 percent, while the average increase in real-time prices for the NEW JERSEY HUB was $3.00 per MWh, 7.9 percent.

Table 3-34 Day-ahead and real-time average DLMP and PLMP for PJM hubs (Dollars per MWh): January through September, 2025

	2025 (Jan-Sep)							
	Day-Ahead				Real-Time			
Hub	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
AEP GEN HUB	$42.22	$42.27	$0.05	0.1%	$38.16	$41.63	$3.48	9.1%
AEP-DAYTON HUB	$43.93	$43.99	$0.05	0.1%	$39.96	$43.56	$3.60	9.0%
ATSI GEN HUB	$43.86	$43.87	$0.00	0.0%	$39.67	$43.21	$3.54	8.9%
CHICAGO GEN HUB	$35.47	$35.54	$0.07	0.2%	$32.14	$35.20	$3.06	9.5%
CHICAGO HUB	$36.40	$36.47	$0.07	0.2%	$33.15	$36.18	$3.03	9.1%
DOMINION HUB	$48.52	$48.56	$0.04	0.1%	$45.66	$49.60	$3.94	8.6%
EASTERN HUB	$43.83	$43.92	$0.09	0.2%	$39.21	$42.96	$3.75	9.6%
N ILLINOIS HUB	$36.30	$36.37	$0.07	0.2%	$33.26	$36.30	$3.05	9.2%
NEW JERSEY HUB	$40.86	$40.93	$0.07	0.2%	$37.92	$40.91	$3.00	7.9%
OHIO HUB	$44.06	$44.12	$0.06	0.1%	$40.15	$43.76	$3.61	9.0%
WEST INT HUB	$45.64	$45.65	$0.02	0.0%	$42.10	$45.79	$3.69	8.8%
WESTERN HUB	$47.61	$47.67	$0.06	0.1%	$43.79	$47.62	$3.82	8.7%

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 2025.

Table 3-35 Frequency of real-time interval difference (dollars per MWh) between zonal DLMP and PLMP: January through September, 2025

	2025 (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%	1.0%	45.5%	42.0%	7.4%	3.4%	0.6%	0.1%	0.0%
AECO	0.0%	0.0%	5.2%	45.7%	40.1%	5.5%	2.7%	0.6%	0.1%	0.0%
AEP	0.0%	0.0%	1.4%	45.6%	41.1%	7.5%	3.6%	0.6%	0.1%	0.0%
APS	0.0%	0.0%	1.1%	45.6%	41.3%	7.4%	3.9%	0.7%	0.1%	0.0%
ATSI	0.0%	0.0%	1.4%	45.5%	41.4%	7.3%	3.5%	0.6%	0.1%	0.0%
BGE	0.0%	0.1%	2.5%	45.4%	37.9%	7.8%	4.8%	1.1%	0.3%	0.0%
COMED	0.2%	0.1%	5.4%	46.5%	37.8%	6.4%	2.9%	0.6%	0.1%	0.0%
DAY	0.0%	0.1%	1.6%	45.6%	40.8%	7.4%	3.6%	0.7%	0.1%	0.0%
DEOK	0.0%	0.1%	1.7%	45.7%	41.0%	7.3%	3.4%	0.6%	0.1%	0.0%
DOM	0.1%	0.3%	2.3%	45.5%	39.1%	7.4%	4.3%	1.0%	0.2%	0.0%
DPL	0.0%	0.2%	6.8%	45.6%	37.6%	5.3%	2.8%	1.0%	0.7%	0.0%
DUQ	0.0%	0.0%	1.5%	45.5%	41.6%	7.2%	3.4%	0.6%	0.1%	0.0%
EKPC	0.0%	0.0%	1.6%	45.6%	41.2%	7.4%	3.4%	0.6%	0.1%	0.0%
JCPL	0.0%	0.0%	3.5%	45.7%	41.7%	5.6%	2.8%	0.6%	0.1%	0.0%
METED	0.0%	0.2%	3.7%	45.5%	40.5%	6.2%	3.2%	0.6%	0.1%	0.0%
OVEC	0.0%	0.2%	1.8%	45.7%	41.1%	7.1%	3.3%	0.6%	0.1%	0.0%
PECO	0.0%	0.1%	6.2%	45.6%	39.3%	5.4%	2.7%	0.6%	0.1%	0.0%
PENELEC	0.0%	0.1%	2.0%	45.3%	41.0%	7.2%	3.6%	0.6%	0.1%	0.0%
PEPCO	0.0%	0.1%	2.4%	45.6%	38.5%	7.7%	4.5%	1.0%	0.2%	0.0%
PPL	0.0%	0.1%	3.8%	45.5%	41.4%	5.7%	2.9%	0.6%	0.1%	0.0%
PSEG	0.0%	0.0%	3.1%	45.7%	42.0%	5.7%	2.8%	0.6%	0.1%	0.0%
RECO	0.0%	0.1%	3.1%	45.4%	41.4%	6.2%	3.1%	0.6%	0.1%	0.0%

Real-Time Average LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[74]

PJM Real-Time Average LMP

Table 3-36 shows the real-time average LMP for the first nine months of 1998 through 2025.[75] The real-time average LMP in the first nine months of 2025 increased $14.57 per MWh, or 46.2 percent, from the first nine months of 2024, from $31.50 per MWh to $46.05 per MWh.

Table 3-36 Real-time average LMP (Dollars per MWh): January through September, 1998 through 2025

	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	$25.56	$18.21	($43.28)	(59.6%)	(57.2%)	(69.5%)
2024	$31.50	$24.73	$26.35	$2.21	7.6%	(3.2%)	44.7%
2025	$46.07	$34.73	$53.62	$14.57	46.2%	40.5%	103.5%

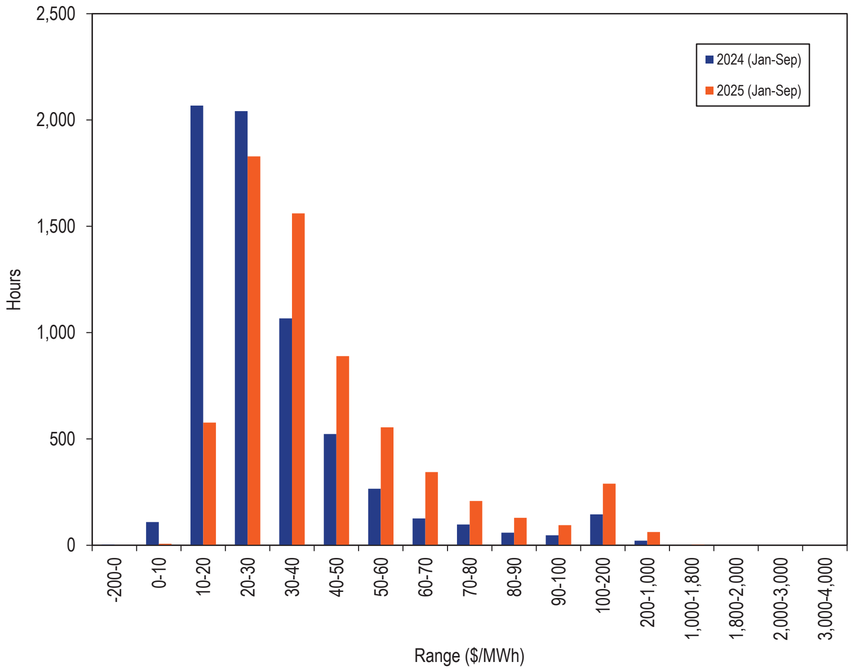
74 See the *Technical Reference for PJM Markets*, at "Calculating Locational Marginal Price," p 16-18 for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

75 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 3-28 shows the hourly distribution of the real-time average LMP in the first nine months of 2024 and 2025. In the first nine months of 2024, the most common price range was $10 to $20 per MWh. In the first nine months of 2025, the most common price range was $20 to $30 per MWh.

Figure 3-28 Distribution of real-time LMP: January through September, 2024 and 2025



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 2025. The real-time load-weighted average LMP in the first nine months of 2025 increased $16.20 per MWh, or 47.2 percent from the first nine months of 2024, from $34.31 per MWh to $50.51 per MWh.

Table 3-37 Real-time load-weighted average LMP (Dollars per MWh): January through September, 1998 through 2025

	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	$26.78	$19.67	($46.97)	(60.3%)	(57.8%)	(71.3%)
2024	$34.31	$26.40	$29.31	$3.44	11.1%	(1.4%)	49.0%
2025	$50.51	$37.12	$64.05	$16.20	47.2%	40.6%	118.5%

PJM Real-Time Monthly Load-Weighted Average LMP

Figure 3-29 shows the real-time monthly and yearly load-weighted average LMP for 1999 through September 2025.

Figure 3-29 Real-time monthly and yearly load-weighted average LMP: 1999 through September 2025

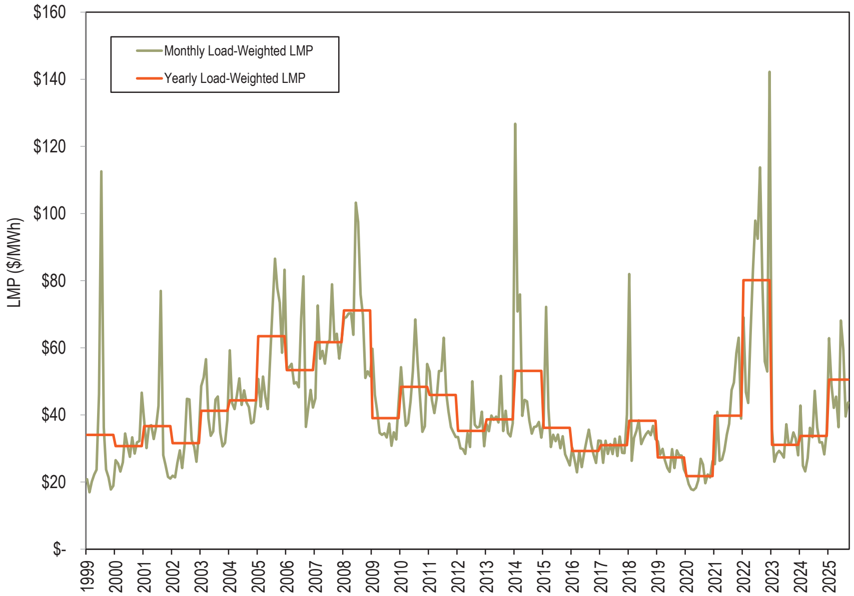


Table 3-38 shows the real-time monthly on peak and off peak load-weighted average LMP for 2024 through September 2025.

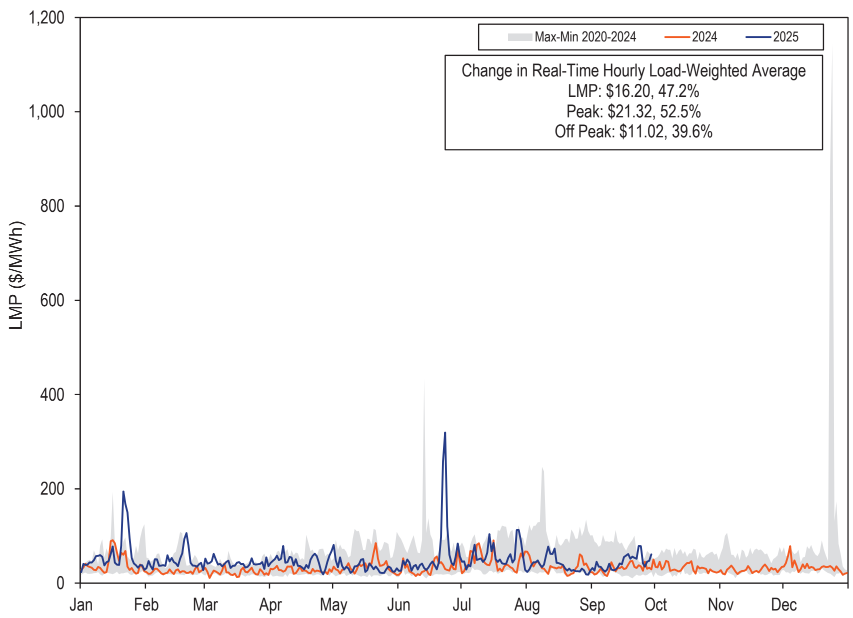
Table 3-38 Real-time monthly on peak and off peak load-weighted average LMP (Dollars per MWh): 2024 through September 2025

	2024				2025			
	Off Peak	On Peak	Difference	Percent Difference	Off Peak	On Peak	Difference	Percent Difference
Jan	$38.50	$47.10	$8.60	22.3%	$55.29	$70.54	$15.25	27.6%
Feb	$24.49	$25.23	$0.74	3.0%	$43.75	$54.12	$10.37	23.7%
Mar	$21.64	$24.79	$3.15	14.6%	$38.89	$45.68	$6.79	17.5%
Apr	$23.99	$30.03	$6.04	25.2%	$38.15	$52.08	$13.93	36.5%
May	$28.99	$42.74	$13.75	47.4%	$27.32	$45.53	$18.21	66.7%
Jun	$26.66	$40.04	$13.38	50.2%	$39.62	$94.51	$54.89	138.5%
Jul	$32.20	$60.78	$28.58	88.7%	$39.08	$77.77	$38.68	99.0%
Aug	$26.71	$44.99	$18.28	68.5%	$29.15	$49.92	$20.77	71.2%
Sep	$24.53	$39.42	$14.89	60.7%	$34.41	$52.55	$18.14	52.7%
Oct	$26.60	$36.49	$9.89	37.2%				
Nov	$23.80	$33.18	$9.38	39.4%				
Dec	$31.60	$38.70	$7.10	22.5%				

PJM Real-Time Daily Load-Weighted Average LMP

Figure 3-30 shows the real-time daily load-weighted average LMP for 2024 through September 2025.

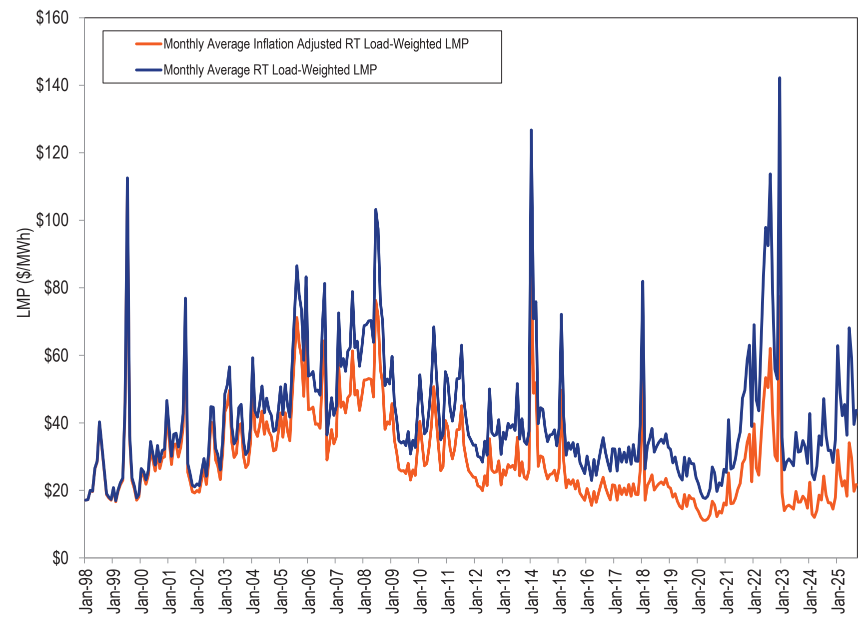
Figure 3-30 Real-time daily load-weighted average LMP: 2024 through September 2025



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

Figure 3-31 shows the PJM real-time monthly load-weighted average LMP and inflation adjusted monthly load-weighted average LMP from January 1998 through September 2025.[76] Table 3-39 shows the PJM real-time load-weighted average LMP and inflation adjusted load-weighted average LMP for every first nine months from 1998 through 2025.

Figure 3-31 Real-time monthly load-weighted average LMP unadjusted and adjusted for inflation: January 1998 through September 2025



76 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 24, 2025)

Table 3-39 Real-time load-weighted and inflation adjusted load-weighted average LMP: January through September, 1998 through 2025

	Load-Weighted Average LMP	Inflation Adjusted Load-Weighted Average LMP
	Jan-Sep	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
2024	$34.31	$17.71
2025	$50.51	$25.40

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).[77] The final real-time LMPs and ancillary service clearing prices are determined for every five minute interval by LPC.

Real-Time SCED and LPC

The 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 for 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. From January 2021 through September 2025, 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 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 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.

77 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 133 (Dec. 17, 2024).

Table 3-40 shows that in the first nine months of 2025, 97.8 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 97.2 percent in all of 2024.

Table 3-40 RT SCED cases solved, approved and used in pricing: January 2024 through September 2025

	2024				2025			
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	45,594	9,161	8,891	97.1%	46,098	9,146	8,895	97.3%
Feb	43,066	8,659	8,288	95.7%	41,310	8,213	8,020	97.7%
Mar	45,340	8,972	8,845	98.6%	46,674	9,013	8,823	97.9%
Apr	44,365	8,767	8,606	98.2%	44,215	8,766	8,608	98.2%
May	46,149	9,177	8,853	96.5%	45,702	9,053	8,867	97.9%
Jun	44,464	8,841	8,598	97.3%	44,319	8,812	8,582	97.4%
Jul	45,629	9,138	8,881	97.2%	45,713	9,076	8,889	97.9%
Aug	45,616	9,192	8,894	96.8%	45,491	9,022	8,860	98.2%
Sep	44,275	8,752	8,550	97.7%	43,744	8,736	8,556	97.9%
Oct	45,806	9,144	8,879	97.1%				
Nov	44,055	8,850	8,607	97.3%				
Dec	45,460	9,120	8,899	97.6%				
Total	539,819	107,773	104,791	97.2%	403,266	79,837	78,100	97.8%

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.[78] Table 3-41 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 2024 and the first nine months of 2025. In the first nine months of 2025, PJM recalculated LMPs for 1,926 five minute intervals or 2.45 percent of the total 78,612 five minute intervals.

78 OA Attachment K Section 1 § 1.10.8(e).

Table 3-41 Number of five minute interval real-time prices recalculated: January 2024 through September 2025

	2024			2025		
Month	Number of Five Minute Intervals	Number of Five Minute Intervals for Which LMPs Were Recalculated	Percent	Number of Five Minute Intervals	Number of Five Minute Intervals for Which LMPs Were Recalculated	Percent
January	8,928	164	1.8%	8,928	154	1.7%
February	8,352	285	3.4%	8,064	189	2.3%
March	8,916	304	3.4%	8,916	680	7.6%
April	8,640	154	1.8%	8,640	126	1.5%
May	8,928	193	2.2%	8,928	153	1.7%
June	8,640	167	1.9%	8,640	162	1.9%
July	8,928	274	3.1%	8,928	183	2.0%
August	8,928	171	1.9%	8,928	137	1.5%
September	8,640	167	1.9%	8,640	142	1.6%
October	8,928	155	1.7%	-	-	
November	8,652	160	1.8%	-	-	
December	8,928	165	1.8%	-	-	
Total	105,408	2,359	2.2%	78,612	1,926	2.5%

Day-Ahead Average LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[79]

PJM Day-Ahead Average LMP

Table 3-42 shows the day-ahead average LMP for the first nine months of 2001 through 2025. The day-ahead average LMP for the first nine months of 2025 increased $14.60 per MWh, or 47.0 percent from the first nine months of 2024, from $31.09 per MWh to $45.69 per MWh.

Table 3-42 Day-ahead average LMP (Dollars per MWh): January through September, 2001 to 2025

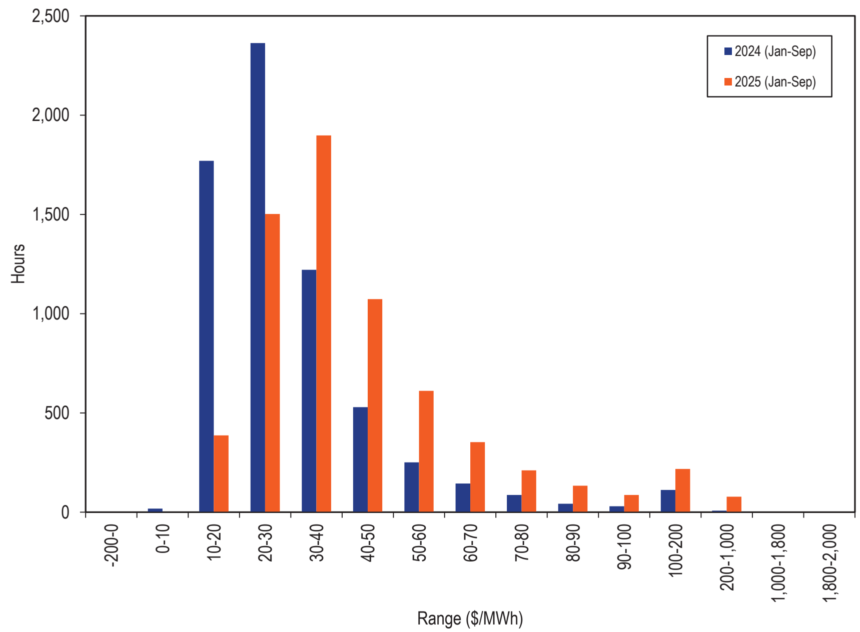
	Day-Ahead LMP			Year to Year Change			
Jan-Sep	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
2001	$36.07	$30.02	$34.25	NA	NA	NA	NA
2002	$28.29	$22.54	$19.09	($7.78)	(21.6%)	(24.9%)	(44.3%)
2003	$41.20	$38.24	$22.02	$12.91	45.6%	69.7%	15.4%
2004	$42.64	$42.07	$17.47	$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%)
2024	$31.09	$25.71	$21.00	$0.99	3.3%	(7.6%)	37.5%
2025	$45.69	$36.75	$35.12	$14.60	47.0%	42.9%	67.2%

79 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 3-32 shows the hourly distribution of the day-ahead average LMP for the first nine months of 2024 and 2025.

Figure 3-32 Distribution of day-ahead LMP: January through September, 2024 and 2025



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 hourly LMP 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 3-43 shows the day-ahead load-weighted average LMP for the first nine months of 2001 through 2025. The day-ahead load-weighted average LMP for the first nine months of 2025 increased $16.03 or 47.4 percent from the first nine months of 2024, from $33.85 per MWh to $49.88 per MWh.

Table 3-43 Day-ahead load-weighted average LMP (Dollars per MWh): January through September, 2001 to 2025

	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%)
2024	$33.85	$27.47	$23.62	$1.95	6.1%	(5.5%)	33.6%
2025	$49.88	$39.06	$40.28	$16.03	47.4%	42.2%	70.5%

PJM Day-Ahead Monthly Load-Weighted Average LMP

Figure 3-33 shows the day-ahead monthly and yearly load-weighted average LMP in 2001 through September 2025.

Figure 3-33 Day-ahead monthly and yearly load-weighted average LMP: 2001 through September 2025

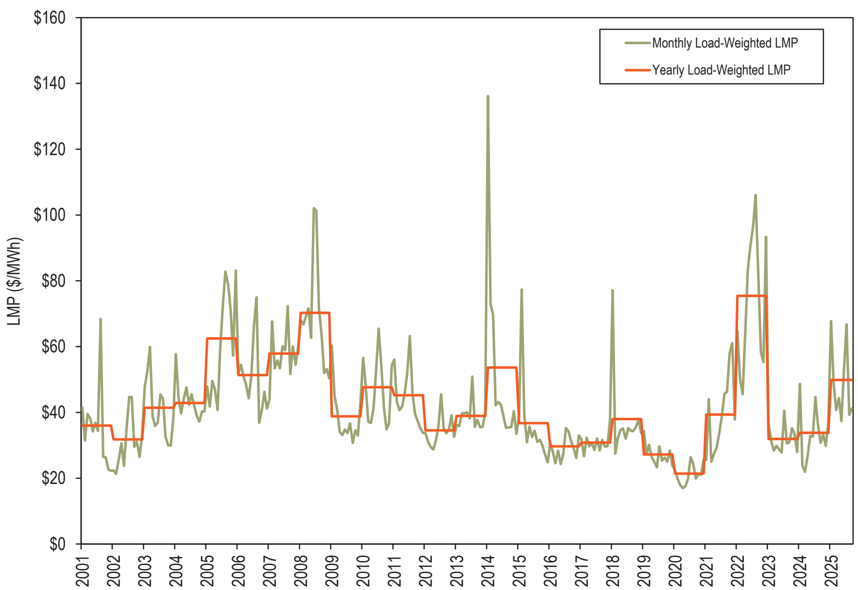
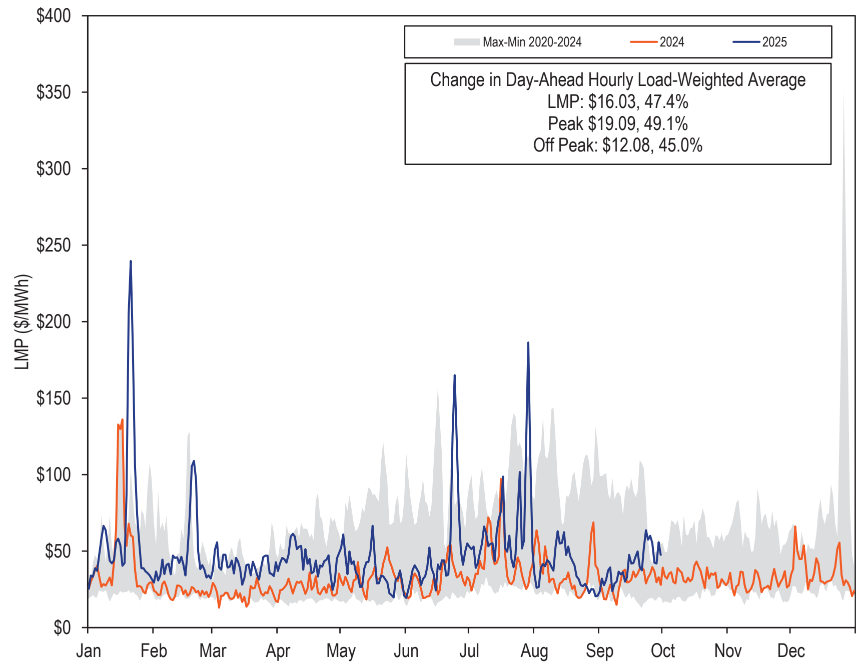


Figure 3-34 shows the day-ahead daily load-weighted average LMP in 2024 through September 2025 compared to the historic five year price range.

Figure 3-34 Day-ahead daily load-weighted average LMP: 2024 through September 2025



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

Figure 3-35 shows the PJM day-ahead monthly load-weighted average LMP and inflation adjusted monthly day-ahead load-weighted average LMP for June 2000 through September 2025.[80] Table 3-44 shows the PJM day-ahead load-weighted average LMP and inflation adjusted load-weighted average LMP for every first nine months from 2000 through 2025.

Figure 3-35 Day-ahead monthly load-weighted and inflation adjusted load-weighted average LMP: June 2000 through September 2025

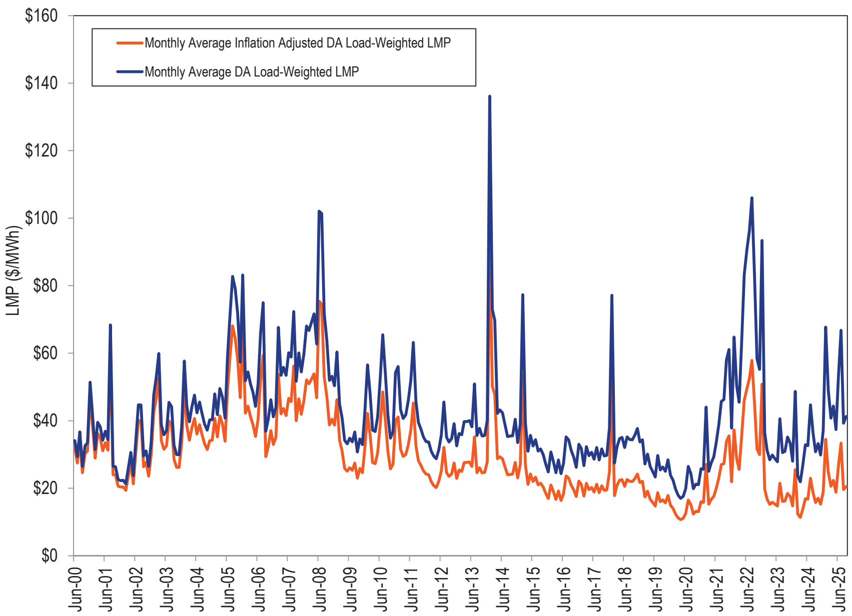


Table 3-44 Day-ahead yearly load-weighted and inflation adjusted load-weighted average LMP: January through September, 2001 through 2025

	Load-Weighted Average LMP	Inflation Adjusted Load-Weighted Average LMP
	Jan-Sep	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
2024	$33.85	$17.48
2025	$49.88	$25.09

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.

80 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 October24, 2025).

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.

In the day-ahead market, load bids are submitted by market buyers at aggregate pnodes, and PJM uses historic bus level load data to distribute the aggregate bids among the bus level pnodes that comprise the aggregate pnode. Effective December 14, 2023, PJM modified the method used to assign load bids to nodes from a single snapshot at 8:00 AM the week prior to the hourly demand data from one week prior to the Operating Day for each hour.[81]

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 3-45 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 source and sink points in the first nine months of 2024 and 2025. In the first nine months of 2025, 40.5 percent of all cleared

81 PJM Interconnection, L.L.C., Tariff Revisions to Improve the Determination of Day-Ahead Zonal Load Factors, Docket No. ER23-1529 (March 31, 2023).

UTC transactions were profitable. Of cleared UTC transactions, 62.7 percent were profitable on the source side and 35.1 percent were profitable on the sink side, but only 8.0 percent were profitable on both the source and sink side.

Table 3-45 Cleared UTCs with positive profits at source and sink points: January through September, 2024 and 2025[82]

(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	Shar Sour
2024	4,486,499	1,780,160	2,732,000	1,674,097	345,697	39.7%	60.9%	37.3%	
2025	4,857,966	1,965,649	3,047,662	1,707,480	388,714	40.5%	62.7%	35.1%	

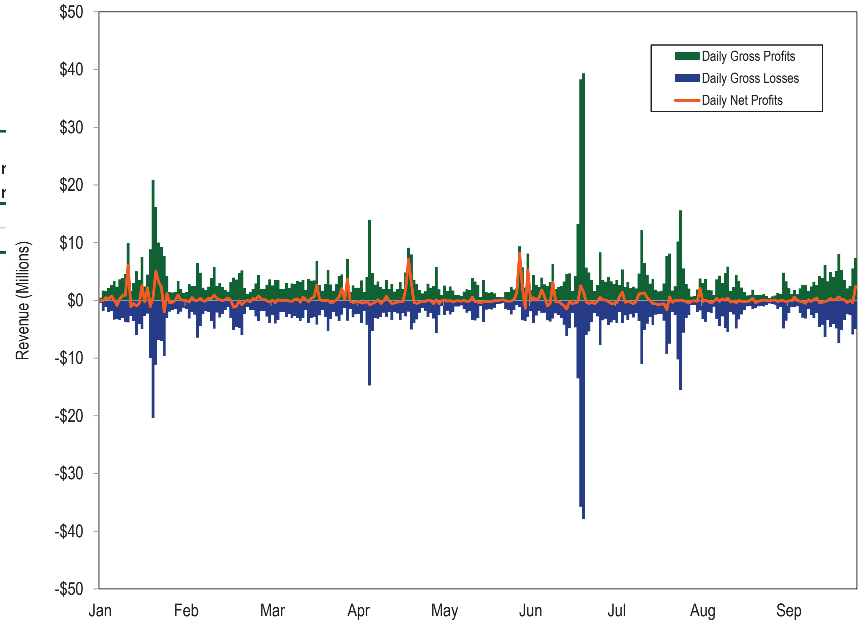
Table 3-46 shows the number of cleared INC and DEC transactions and the number of profitable transactions in the first nine months of 2024 and 2025. Of cleared INC and DEC transactions in the first nine months of 2025, 51.7 percent of INCs were profitable and 30.9 percent of DECs were profitable.

Table 3-46 Cleared INC and DEC transactions with positive profits: January through September, 2024 and 2025

(Jan-Sep)	Cleared INC	Profitable INC	Profitable INC Share	Cleared DEC	Profitable DEC	Profitable DEC Share
2024	2,794,484	1,422,401	50.9%	2,505,187	794,620	31.7%
2025	3,480,378	1,798,995	51.7%	3,253,797	1,006,376	30.9%

Figure 3-36 shows the positive, negative, and net daily profits for UTCs in the first nine months of 2025.

Figure 3-36 Positive, negative, and net daily UTC profits: January through September, 2025



82 Calculations exclude PJM administrative charges.

Figure 3-37 shows the cumulative UTC daily total net profits for each year from 2013 through September 2025.[83] Administrative charges are included for all dates, and uplift charges are included starting from November 1, 2020, when uplift was first charged to UTCs.

Figure 3-37 Cumulative daily UTC profits: January 2013 through September 2025

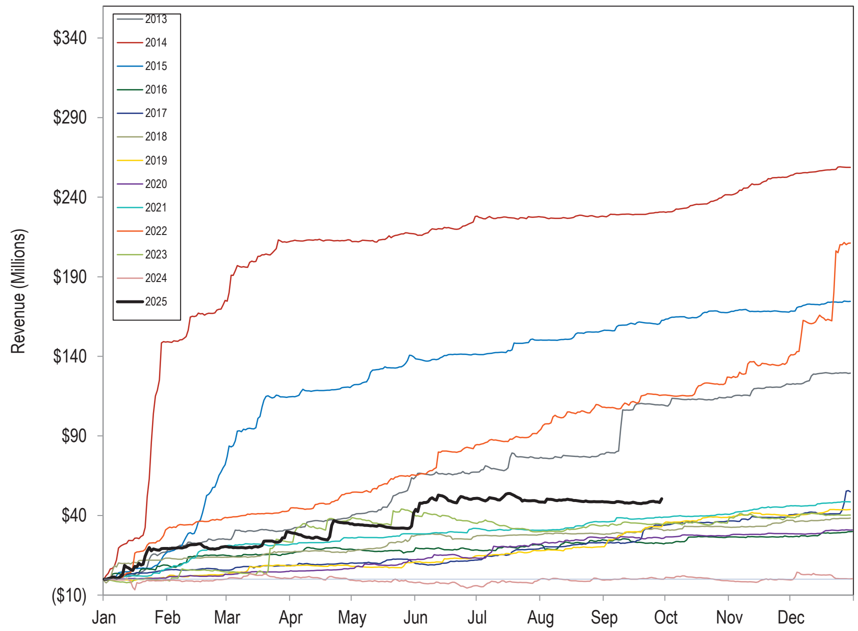


Table 3-47 shows UTC monthly total net profits for January 2013 through September 2025. Administrative charges are included for all months and uplift charges are included starting from November 1, 2020, when uplift was first charged to UTCs. UTC profits were $211 million in 2022, higher than any year since 2014, with the largest monthly total in December 2022 at $75 million. In 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. The year 2024 was the least profitable year ever for UTC transactions, with very large profitable days occurring with less frequency than prior years. DOMINION HUB to DOM_RESID_AGG UTC remains the path with the highest cleared volume in the first nine months of 2025, June 2025 was the most profitable summer month for UTCs since August 2022.

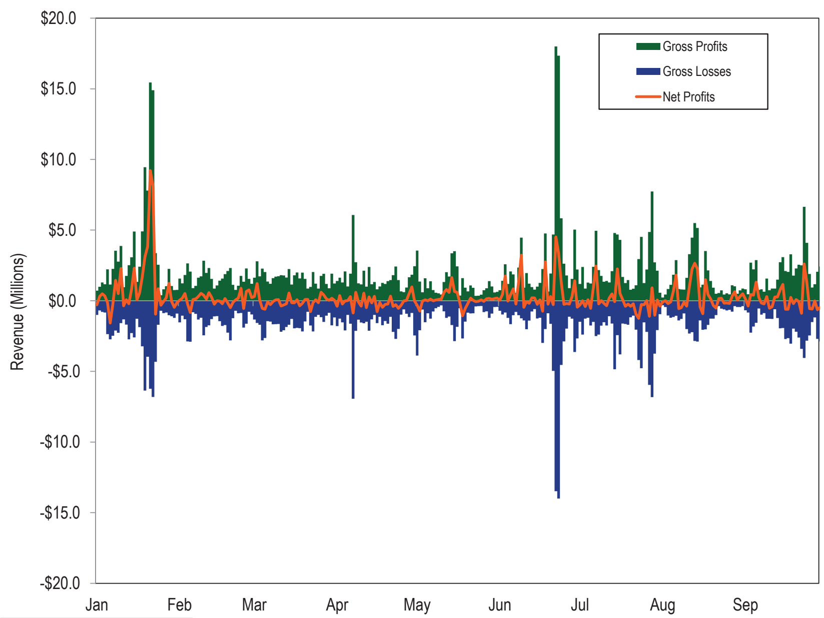
83 UTCs paid uplift only after October 31, 2020.

Table 3-47 UTC profits by month: January 2013 through September 2025

	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	$787,185	$3,734,966	$1,259,381	$40,276,272
2024	($798,085)	$741,801	$505,530	($1,048,989)	($1,481,223)	($1,997,609)	$3,605,145	($28,816)	$440,898	($852,701)	$472,000	$677,521	$235,473
2025	$19,307,539	$965,550	$9,446,437	$5,569,957	($1,921,483)	$17,309,458	($1,634,565)	($406,499)	$1,936,052				$50,572,446

Figure 3-38 shows the positive, negative, and net daily profits for INCs and DECs in the first nine months of 2025. Differences in the modeling of transmission constraints 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 3-38 Daily gross profits, gross losses, and net profits of all INC and DEC transactions: January through September, 2025[84]



84 Calculations exclude PJM administrative charges.

Figure 3-39 shows the positive, negative, and net daily profits for INCs in the first nine months of 2025.

Figure 3-39 Daily gross profits, gross losses, and net profits for INC transactions: January through September, 2025[85]

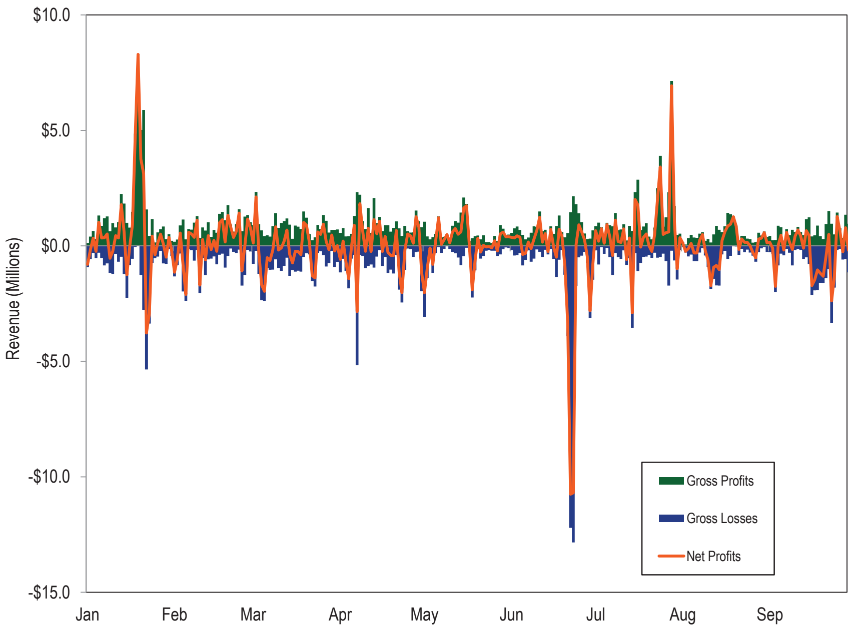
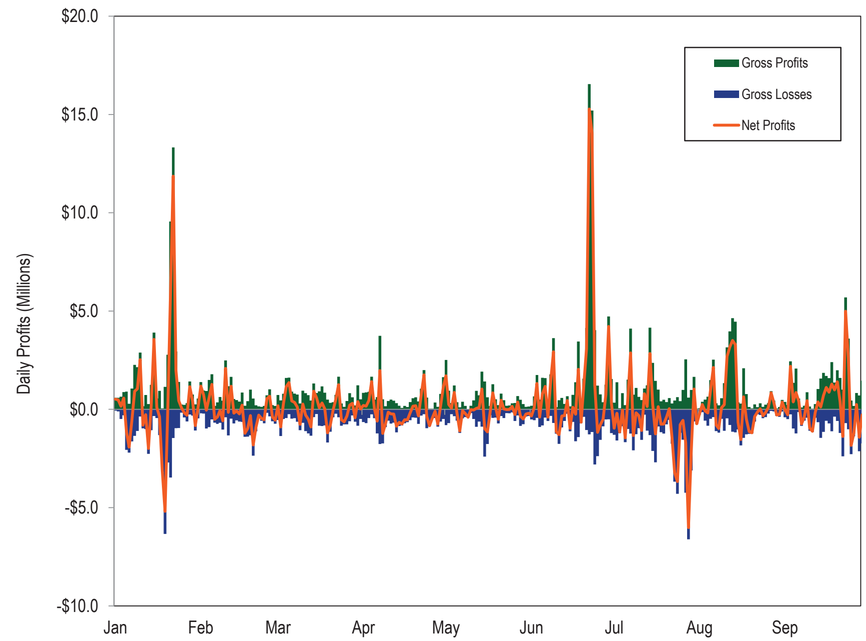


Figure 3-40 shows the positive, negative, and net daily profits for DECs in the first nine months of 2025.

Figure 3-40 Daily gross profits, gross losses, and net profits for DEC transactions: January through September, 2025



85 Calculations exclude PJM administrative charges.

Figure 3-41 shows the cumulative INC and DEC daily profits in the first nine months of 2025. 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 3-41 Cumulative daily INC and DEC profit: January through September, 2025

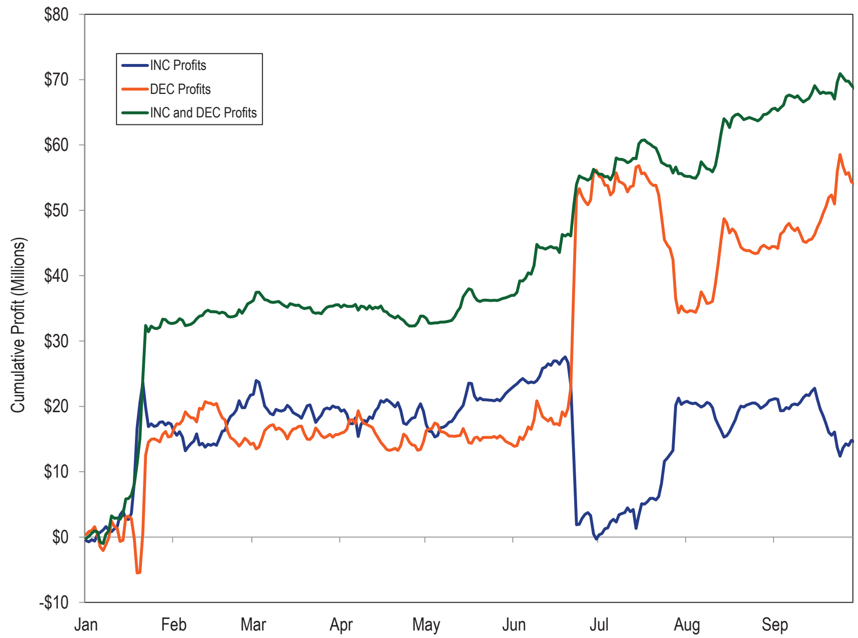


Table 3-48 shows INC and DEC profits by month in the first nine months of 2025.

Table 3-48 INC and DEC profits by month: January through September, 2025

Month	January	February	March	April	May	June	July	August	September	Total
INCs	$17,506,715	$3,444,425	($1,114,741)	$550,610	$1,968,221	($21,882,359)	$19,815,130	$611,357	($6,283,299)	$14,616,059
DECs	$15,315,025	($575,819)	$944,652	($2,254,255)	$990,626	$41,395,416	($20,450,397)	$8,744,220	$9,946,108	$54,055,576
INCs and DECs	$32,821,739	$2,868,606	($170,089)	($1,703,644)	$2,958,846	$19,513,057	($635,267)	$9,355,577	$3,662,809	$68,671,635

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.

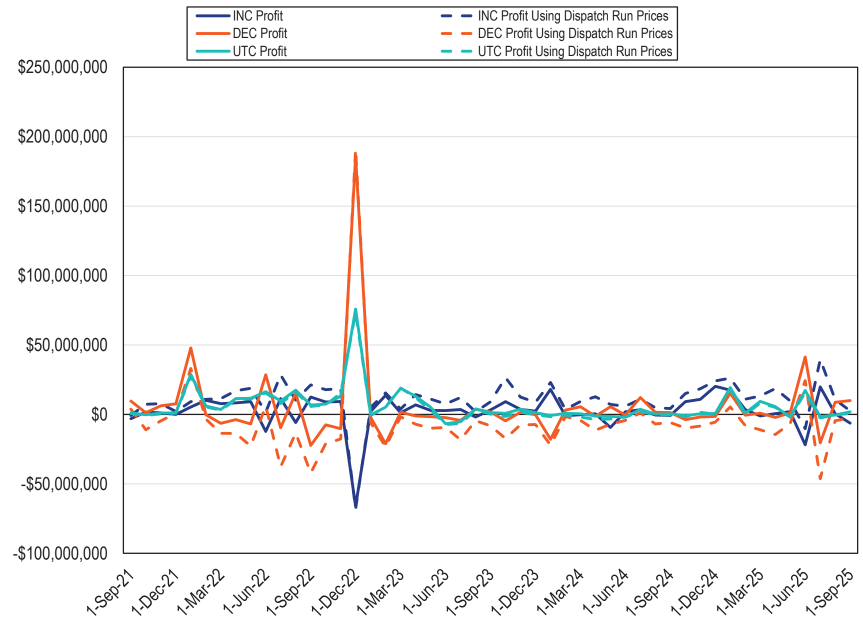
In the first nine months of 2025, INCs paid a total of $19.6 million, DECs paid a total of $24.1 million, and UTCs paid a total of $46.3 million in uplift. This compares to total INC profits of $14.6 million, total DEC profits of $54.1 million, and total UTC profits of $50.7 million.

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 3-42 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 3-42 Monthly profits for virtuals using pricing run versus dispatch run prices: September 1, 2021 through September 30, 2025



From the implementation of fast start pricing on September 1, 2021, through September 30, 2025, the cumulative difference in profit between the pricing run and the dispatch run for INCs was -$387.0 million, the cumulative difference in profit for DECs was $499.5 million, and the cumulative difference in profit for UTCs was $44.8 million. Fast start pricing led to a net increase of $157.3 million in cumulative profits for virtual transactions since September 1, 2021.

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 3-49 shows the difference between the day-ahead and the real-time average LMP in the first nine months of 2024 and 2025.

Table 3-49 Day-ahead and real-time average LMP (Dollars per MWh): January through September, 2024 and 2025[86]

	2024 (Jan-Sep)				2025 (Jan-Sep)			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$31.09	$31.50	$0.41	1.3%	$45.69	$46.07	$0.38	0.8%
Median	$25.71	$24.73	($0.98)	(4.0%)	$36.75	$34.73	($2.02)	(5.8%)
Standard deviation	$21.00	$26.35	$5.35	20.3%	$35.12	$53.62	$18.49	34.5%
Peak average	$37.94	$37.89	($0.05)	(0.1%)	$56.19	$57.01	$0.81	1.4%
Peak median	$31.43	$29.87	($1.57)	(5.2%)	$44.51	$41.89	($2.62)	(6.3%)
Peak standard deviation	$24.51	$29.38	$4.87	16.6%	$43.36	$71.50	$28.14	39.4%
Off peak average	$25.09	$25.91	$0.82	3.2%	$36.51	$36.51	($0.00)	(0.0%)
Off peak median	$21.40	$20.60	($0.80)	(3.9%)	$31.64	$30.41	($1.23)	(4.1%)
Off peak standard deviation	$14.97	$21.89	$6.92	31.6%	$22.08	$26.90	$4.81	17.9%

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

Table 3-50 shows the difference between the day-ahead and the real-time load-weighted LMP in the first nine months of 2001 through 2025.

Table 3-50 Day-ahead and real-time load-weighted average LMP (Dollars per MWh): January through September, 2001 through 2025

Load-Weighted Average LMP						
Jan-Sep	Day-Ahead	Real-Time	Difference	Percent of Real-Time	Average Absolute Difference	Average Absolute Difference as a Percent of Real-Time
2001	$39.88	$40.96	$1.09	2.7%	$11.88	29.0%
2002	$32.29	$31.95	($0.33)	(1.0%)	$7.16	22.4%
2003	$44.11	$43.57	($0.54)	(1.2%)	$12.54	28.8%
2004	$44.59	$46.44	$1.84	4.0%	$9.92	21.4%
2005	$59.51	$60.44	$0.93	1.5%	$12.35	20.4%
2006	$54.19	$56.39	$2.19	3.9%	$12.02	21.3%
2007	$57.79	$61.83	$4.05	6.5%	$14.63	23.7%
2008	$75.96	$77.27	$1.30	1.7%	$17.70	22.9%
2009	$39.35	$39.57	$0.21	0.5%	$6.19	15.6%
2010	$49.12	$49.91	$0.79	1.6%	$9.82	19.7%
2011	$48.34	$49.48	$1.14	2.3%	$10.05	20.3%
2012	$34.29	$35.02	$0.73	2.1%	$6.33	18.1%
2013	$39.49	$39.75	$0.26	0.7%	$6.47	16.3%
2014	$59.09	$58.60	($0.49)	(0.8%)	$16.25	27.7%
2015	$39.51	$38.94	($0.57)	(1.5%)	$9.14	23.5%
2016	$29.69	$29.32	($0.37)	(1.3%)	$5.76	19.6%
2017	$30.26	$30.36	$0.10	0.3%	$4.17	13.7%
2018	$38.71	$39.43	$0.73	1.8%	$8.38	21.3%
2019	$27.70	$27.60	($0.10)	(0.4%)	$4.64	16.8%
2020	$20.95	$21.22	$0.28	1.3%	$3.52	16.6%
2021	$35.51	$35.68	$0.17	0.5%	$6.87	19.3%
2022	$76.97	$77.84	$0.87	1.1%	$13.91	17.9%
2023	$31.90	$30.87	($1.03)	(3.3%)	$6.95	22.5%
2024	$33.85	$34.31	$0.46	1.3%	$8.79	25.6%
2025	$49.88	$50.51	$0.63	1.2%	$13.15	26.0%

Table 3-51 includes frequency distributions of the differences between the day-ahead and the real-time load-weighted LMP in the first nine months of 2024 and 2025.

Table 3-51 Frequency distribution by hours of real-time load-weighted LMP minus day-ahead load-weighted LMP (Dollars per MWh): January through September, 2024 and 2025

	2024 Jan - Sep		2025 Jan - Sep	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($200)	0	0.0%	6	0.1%
($200) to ($100)	5	0.1%	31	0.6%
($100) to ($50)	48	0.8%	72	1.7%
($50) to $0	3,991	61.5%	3,988	62.5%
$0 to $50	2,419	98.3%	2,295	97.6%
$50 to $100	81	99.5%	108	99.2%
$100 to $200	24	99.9%	35	99.8%
$200 to $400	6	100.0%	8	99.9%
$400 to $800	1	100.0%	4	99.9%
>= $800	0	100.0%	4	100.0%

Figure 3-43 shows the differences between day-ahead and real-time hourly average LMP in the first nine months of 2025.

The largest difference was $1,436.65 per MWh on June 24, 2025.

Figure 3-43 Real-time hourly average LMP minus day-ahead hourly average LMP: January through September, 2025

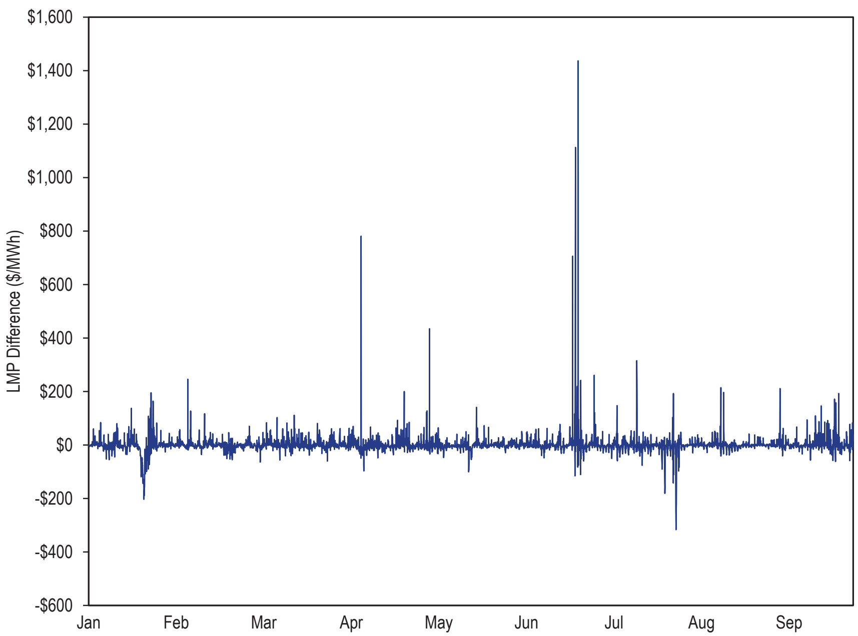
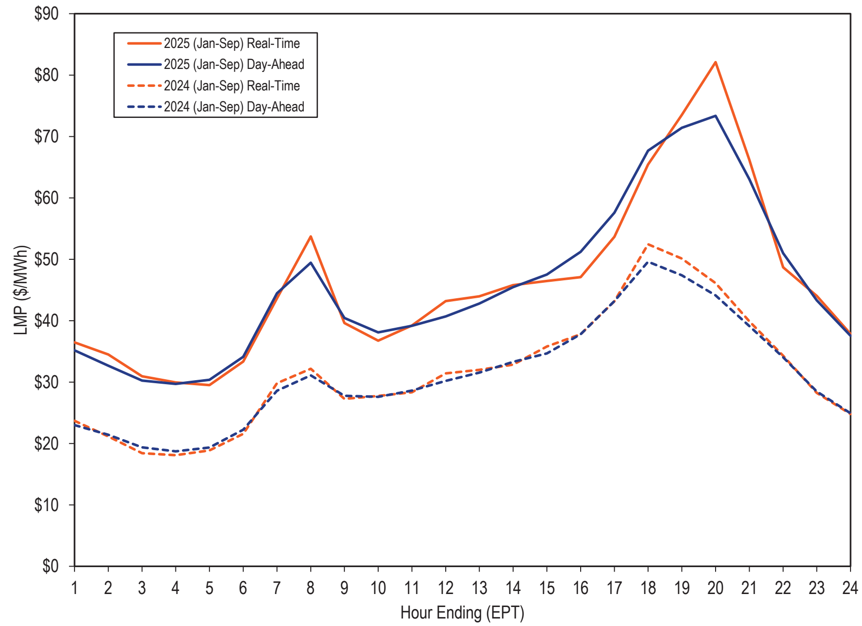


Figure 3-44 shows day-ahead and real-time load-weighted average LMP by hour of the day in the first nine months of 2024 and 2025.

Figure 3-44 System hourly average LMP: January through September, 2024 and 2025



Zonal LMP and Dispatch

Table 3-52 shows real-time zonal average and load-weighted average LMP for the first nine months of 2024 and 2025.

Table 3-52 Real-time zonal average and load-weighted average LMP (Dollars per MWh): January through September, 2024 and 2025

	Real-Time Average LMP			Real-Time Load-Weighted Average LMP		
	2024	2025	Percent	2024	2025	Percent
Zone	Jan-Sep	Jan-Sep	Change	Jan-Sep	Jan-Sep	Change
ACEC	$27.34	$40.34	47.5%	$31.01	$47.19	52.2%
AEP	$31.29	$45.00	43.8%	$33.43	$48.10	43.9%
APS	$31.98	$46.12	44.2%	$34.63	$50.50	45.8%
ATSI	$31.41	$44.17	40.6%	$33.78	$47.53	40.7%
BGE	$40.58	$55.16	35.9%	$46.83	$62.73	33.9%
COMED	$26.14	$36.27	38.8%	$29.08	$40.72	40.0%
DAY	$32.62	$44.72	37.1%	$35.47	$48.47	36.7%
DUKE	$31.16	$43.25	38.8%	$33.74	$46.80	38.7%
DOM	$36.51	$58.40	60.0%	$39.78	$64.13	61.2%
DPL	$31.02	$43.46	40.1%	$36.68	$51.57	40.6%
DUQ	$31.35	$43.13	37.6%	$33.98	$46.64	37.3%
EKPC	$30.85	$43.91	42.4%	$33.86	$48.65	43.7%
JCPLC	$27.43	$40.59	48.0%	$31.14	$47.59	52.8%
MEC	$28.17	$42.63	51.3%	$30.84	$47.58	54.3%
OVEC	$29.64	$41.75	40.8%	$29.82	$42.31	41.9%
PECO	$27.01	$39.25	45.3%	$30.31	$44.43	46.6%
PE	$31.27	$46.44	48.5%	$33.09	$49.94	50.9%
PEPCO	$37.85	$54.19	43.2%	$42.92	$61.79	44.0%
PPL	$26.57	$38.82	46.1%	$28.86	$43.21	49.7%
PSEG	$27.77	$41.43	49.2%	$30.54	$46.85	53.4%
REC	$29.56	$45.05	52.4%	$32.80	$51.59	57.3%
PJM	$31.50	$46.07	46.2%	$34.31	$50.51	47.2%

Table 3-53 shows day-ahead zonal average and load-weighted average LMP for the first nine months of 2024 and 2025.

Table 3-53 Day-ahead zonal average and load-weighted average LMP (Dollars per MWh): January through September, 2024 and 2025

	Day-Ahead Average LMP			Day-Ahead Load-Weighted Average LMP		
	2024	2025	Percent	2024	2025	Percent
Zone	Jan-Sep	Jan-Sep	Change	Jan-Sep	Jan-Sep	Change
ACEC	$27.01	$40.75	50.9%	$30.36	$46.30	52.5%
AEP	$30.60	$44.65	45.9%	$32.81	$47.73	45.5%
APS	$31.78	$45.54	43.3%	$34.29	$49.21	43.5%
ATSI	$30.90	$44.62	44.4%	$33.15	$47.71	43.9%
BGE	$40.32	$55.00	36.4%	$46.10	$62.03	34.5%
COMED	$25.88	$36.40	40.7%	$28.37	$40.47	42.6%
DAY	$32.07	$45.24	41.1%	$34.91	$48.87	40.0%
DUKE	$30.83	$43.83	42.2%	$33.48	$47.35	41.4%
DOM	$36.72	$57.38	56.3%	$40.21	$63.63	58.3%
DPL	$30.96	$44.29	43.1%	$37.04	$52.37	41.4%
DUQ	$30.54	$43.01	40.9%	$33.22	$46.24	39.2%
EKPC	$30.08	$43.48	44.5%	$33.24	$48.68	46.4%
JCPLC	$26.94	$40.92	51.9%	$29.95	$46.19	54.2%
MEC	$28.46	$43.31	52.1%	$31.03	$47.77	54.0%
OVEC	$29.23	$42.39	45.0%	$28.68	$41.61	45.1%
PECO	$26.72	$39.71	48.6%	$29.71	$44.14	48.6%
PE	$31.37	$46.92	49.6%	$33.26	$50.04	50.5%
PEPCO	$37.97	$54.11	42.5%	$43.54	$61.38	41.0%
PPL	$26.60	$39.18	47.3%	$28.74	$43.21	50.3%
PSEG	$27.16	$41.11	51.3%	$29.66	$45.31	52.8%
REC	$29.16	$44.83	53.7%	$31.96	$49.44	54.7%
PJM	$31.09	$45.69	47.0%	$33.85	$49.88	47.4%

Figure 3-45 is a map of the real-time load-weighted average LMP in the first nine months of 2025. In the legend, green represents the real-time load-weighted average LMP in the first nine months of 2025 and each increment to the right represents five percent of the pricing nodes above the real-time load-weighted average LMP in the first nine months of 2025 and each increment to the left represents 25 percent of the pricing nodes below the real-time load-weighted average LMP in the first nine months of 2025.

Figure 3-45 Real-time load-weighted average LMP: January through September, 2025

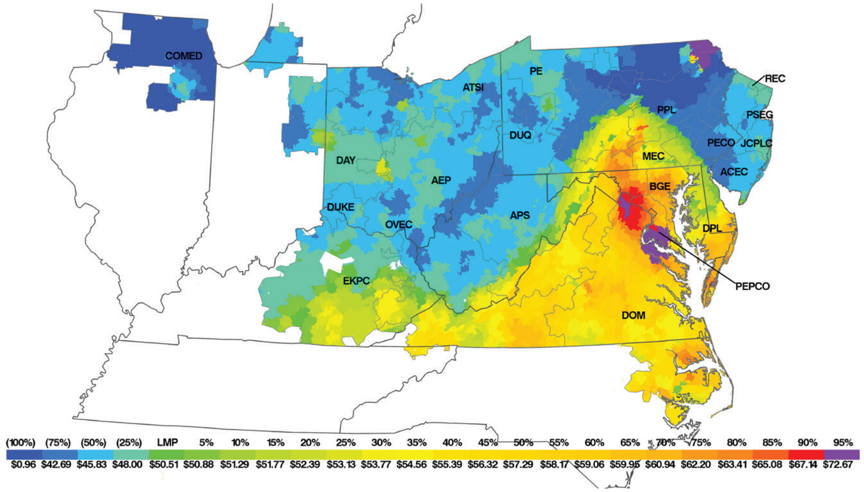


Figure 3-46 Real-time load-weighted average LMP map: January through September, 2022 through 2025

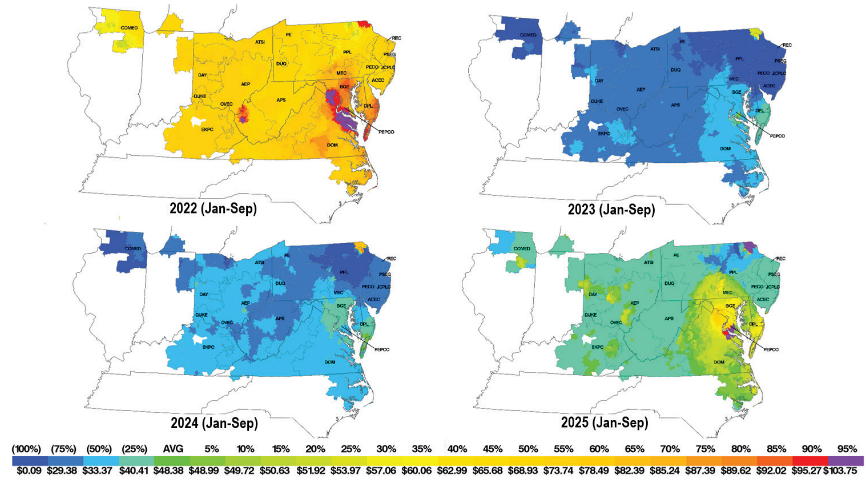


Figure 3-46 includes maps of the real-time load-weighted average LMP in the first nine months of 2022 through 2025. In the legend, green represents the average price in the first nine months of 2022 through 2025 and each block to the right represents five percent of the pricing nodes above the average price in the first nine months of 2022 through 2025 and each block to the left represents 25 percent of the pricing nodes below the average price in the first nine months of 2022 through 2025.

Transmission Constraint Penalty Factors (TCPF)

LMPs are generally set by the offer prices of marginal resources. When a transmission constraint is binding, the flow on the constraint is equal to its limit and the shadow price of the constraint is a function of offer prices of marginal resources. LMP may, at times, be set by transmission constraint penalty factors. When a transmission constraint is limiting 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 constraint penalty factors. The shadow price directly affects the LMP. Transmission constraint penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing, but only when properly applied. The TCPFs are applied incorrectly about 94 percent of the time. In addition, it is not clear that the line ratings are correctly defined, by duration of the flow and ambient conditions, by the transmission owners who have sole control over the line ratings with no meaningful oversight.

PJM operators routinely reduce the control limits on transmission constraint line ratings used in the market clearing software (SCED) by setting the control limits to 95 percent of the actual line ratings.[87] The result is that transmission constraint penalty factors set price much more frequently than needed or appropriate. PJM reduces the control limits both to control for actual flows and for flows that would only result from a contingency (N-1).

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 3-54 shows the frequency and average shadow price of transmission constraints in the PJM real-time market. In the first nine months of 2025, there were 158,826 transmission constraint five minute intervals in the real-time market with a nonzero shadow price. For 18,497, or 11.6 percent, of these transmission constraint intervals, the control limit was violated, meaning that the flow exceeded the facility limit used in SCED.[88] The data on violations includes both violations that result from reductions in the SCED control limit by PJM and violations that are based on the actual line ratings. Of the 18,497 constraint intervals, PJM used actual line limits for 2,773 or 1.7 percent of the constraint intervals. For the remaining 15,724 or 9.9 percent of the constraint intervals, PJM used reduced line limits. In those cases, the actual line limit was not violated. In all cases where violations resulted from reductions by PJM from actual line ratings the shadow prices and resulting LMPs were set by the violation penalty factors. In the first nine months of 2025, the average shadow price of transmission constraints ($1,995.20)) when the line limit used in SCED was violated with a reduced line limit was 6.4 times higher than when the transmission constraint was binding but not violated ($310.95) at its limit used in SCED.

87 Actual transmission line limits are set by the transmission owner. PJM chooses the control limits. At present the actual line rating methods are not reviewed by FERC, or PJM, or the MMU.

88 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.

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 3-54 Frequency and average shadow price of transmission constraints in the real-time market: January through September, 2024 and 2025

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2024 (Jan - Sep)	2025 (Jan - Sep)	2024 (Jan - Sep)	2025 (Jan - Sep)
Violated Transmission Constraints (Actual)	441	2,773	$677.59	$943.53
Violated Transmission Constraints (Reduced)	9,320	15,724	$1,979.52	$1,995.20
Binding Transmission Constraints	99,671	104,982	$215.40	$310.95
Market to Market Transmission Constraints	40,642	35,347	$264.81	$426.85
All Transmission Constraints	150,074	158,826	$339.69	$514.53

Table 3-55 shows the frequency and average shadow price of transmission constraints in the PJM day-ahead market. In the first nine months of 2025, there were 56,386 transmission constraint hours in the day-ahead market with a nonzero shadow price. For 145, or 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 day-ahead pricing run solution.

Table 3-55 Frequency and average shadow price of transmission constraints in the day-ahead market: January through September, 2024 and 2025

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2024 (Jan - Sep)	2025 (Jan - Sep)	2024 (Jan - Sep)	2025 (Jan - Sep)
Violated Transmission Constraints (Actual)	31	145	$2,000.00	$2,000.00
Market to Market Transmission Constraints	52,558	48,900	$64.81	$103.01
Binding Transmission Constraints	4,880	7,341	$105.35	$145.23
All Transmission Constraints	57,469	56,386	$69.29	$113.39

Table 3-56 shows the frequency of violated transmission constraints by voltage level in the real-time market. In the first nine months of 2025, 76.4 percent of the violated transmission constraint intervals had a voltage level at or below 230 kV.

Table 3-56 Frequency of PJM violated transmission constraints in the real-time market by voltage: January through September, 2024 and 2025

	2024 (Jan - Sep)		2025 (Jan - Sep)	
Voltage	Frequency (Constraint Intervals)	Percent	Frequency (Constraint Intervals)	Percent
1 kV	56	0.6%	269	1.5%
69 kV	702	7.2%	1,069	5.8%
115 kV	1,928	19.8%	5,794	31.3%
138 kV	2,772	28.4%	3,422	18.5%
161 kV	16	0.2%	-	0.0%
230 kV	2,536	26.0%	3,585	19.4%
345 kV	618	6.3%	486	2.6%
500 kV	911	9.3%	3,825	20.7%
765 kV	222	2.3%	47	0.3%
Total	9,761	100.0%	18,497	100.0%

Transmission constraint 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.[89] 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.[90] This could be the result of a lengthy planned transmission outage, for example.[91] It can also result from PJM reducing the control limit on the line rating 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 the control limit on the transmission line ratings in SCED to trigger the inclusion of transmission constraint penalty factors in price. In addition, PJM has no information about the accuracy of the line ratings that are determined by each transmission owner. It is not clear whether the line ratings that trigger the transmission constraint penalty factors are defined for the actual expected period of the power flow on the line. Line ratings vary significantly by duration of power flows, and by ambient conditions.

PJM also revised the tariff to list the conditions under which transmission constraint 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 reducing the transmission constraint penalty factors below the default $2,000 per MWh for constraints that are violated due to a transmission outage caused by the construction of upgrades to relieve congestion, for which limited generation resources are available to provide relief.[92]

PJM routinely, based on discretion, reduces the control limits on the transmission constraint line ratings modeled in SCED to below 100 percent, generally to 95 percent of the actual limit, administratively triggering the use of transmission constraint penalty factors.[93] The control limits set the limit of the constraint modeled in SCED. For example, in SCED, a transmission facility with a 100 MW line rating set at a 90 percent control limit would be modeled as a constraint with a limit of 90 MW. Table 3-57 shows the frequency of changes to the control limits for transmission constraints for binding and violated transmission constraints in the PJM real-time market. In the first nine months of 2025, there were 15,724, or 85 percent, of 18,497 violated transmission constraint intervals in the real-time market with a control limit less than 100 percent. In the first nine months of 2025, among the constraints

89 PJM applied a procedure that PJM termed constraint relaxation logic, under which a revised SCED dispatch solution was obtained with an artificially increased limit for the violated transmission facility. The logic typically resulted in reducing the shadow prices to be slightly below the defined constraint violation penalty factor.

90 See Comments of the Independent Market Monitor for PJM, Docket No. EL22-26-000 et al. (February 1, 2022); 178 FERC ¶ 61,104 (2022).

91 See *id.*

92 See 182 FERC ¶ 61,183 (March 21, 2023). The Commission approved PJM's proposed tariff revisions to allow PJM to lower transmission constraint penalty factors generally for any situation similar to the high prices caused by Lanexa-Dunnsville-Northern Neck line outage in the Northern Neck peninsula in Virginia.

93 Actual transmission line limits are set by the transmission owner. PJM chooses the control limits. At present the actual line rating methods are not reviewed by FERC, or PJM, or the MMU.

with a reduced control limit, the constraint limit was reduced on average by 5.1 percent. In the first nine months of 2025, there were 101,632, or 97 percent, of 104,982 binding transmission constraint intervals in the real-time market with a control limit less than 100 percent. By arbitrarily lowering transmission facility limits, PJM is not using the full transmission system capacity available to serve the load to achieve the least cost dispatch solution. The cost to serve the load and the load payments would be lower had PJM not reduced the transmission line ratings.

Table 3-57 Frequency of reduction in control limit of line ratings (constraint intervals) in the real-time market: January through September, 2024 and 2025

	Frequency (Constraint Intervals)		Constraints with Reduced Control Percent (Constraint Intervals)		Average Reduction (Percent)	
Description	2024 (Jan - Sep)	2025 (Jan - Sep)	2024 (Jan - Sep)	2025 (Jan - Sep)	2024 (Jan - Sep)	2025 (Jan - Sep)
Violated Transmission Constraints (Actual)	441	2,773	-	-	0.0%	0.0%
Violated Transmission Constraints (Reduced)	9,320	15,724	9,320	15,724	5.0%	5.1%
Binding Transmission Constraints	99,671	104,982	98,944	101,632	5.3%	5.8%
Market to Market Transmission Constraints	40,642	35,347	14,026	13,056	5.9%	7.2%
All Transmission Constraints	150,074	158,826	122,290	130,412	5.3%	5.9%

Table 3-58 shows the reasons provided by the PJM operators for changing the control limit on the line rating for violated transmission constraints. In the first nine months of 2025, of the 15,724 violated transmission constraint intervals with reduced control limits, no reason was provided for 12,698 cases, or 80.8 percent of all the cases. In 1,952 cases, or 12.4 percent, the control limits were reduced because the relief calculated by the SCED optimization was less than the operator's desired relief for the transmission constraint. In 13 cases, or 0.1 percent, the control limits were reduced because PJM designates the constraint as a thermal surrogate. Thermal surrogate constraints are constraints that PJM activates and for which PJM generally reduces the line rating to enable specific resources called on to control a constraint to set price.

The MMU recommends that PJM end the practice of manual and automated discretionary reductions in the control limits on transmission constraint line ratings used in the market clearing software (SCED) and included in LMP. This practice has significant market effects by limiting economic power flows and increasing prices above the level that would exist if 100 percent of the actual line rating were used in clearing the market and setting energy market prices.

Table 3-58 PJM's reasons for reduction in control limits of line ratings (constraint intervals) in the real-time market: January through September, 2024 and 2025

	Constraint Intervals		Average Reduction (Percent)	
Reason	2024 (Jan - Sep)	2025 (Jan - Sep)	2024 (Jan - Sep)	2025 (Jan - Sep)
No reason provided	8,013	12,698	4.5%	4.4%
Prepositioning of generation resources to support an operational requirement	38	313	8.7%	8.7%
Inadequate relief calculated by the SCED optimization	897	1,952	6.7%	7.6%
Transmission owner identified the flow on their constraint to be greater than PJM's calculated flow on the same constraint.	47	195	8.2%	7.6%
Modeled constraint is a thermal surrogate	101	13	21.2%	52.2%
Power flow on the constraint is volatile due to various system conditions	224	553	7.3%	7.3%
All violated constraints	9,320	15,724	5.0%	5.1%

Table 3-59 shows the impact on LMP of PJM dispatchers reducing the control limit of line ratings of transmission constraints and causing artificial line limit violations.[94] The transmission constraint penalty factor contribution to the load-weighted average LMP in the first nine months of 2025 was $5.31 per MWh or $3.25 billion of the total $30.9 billion cost of real-time load. This impact includes reductions to the line limits of violated constraints on high load summer days, June 23 and 24, 2025. 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 $0.03 per MWh, a 99.4 percent reduction.

Table 3-59 Real-time LMP effect of reduced control limits on transmission constraint line ratings (Dollars per MWh): January through September, 2024 and 2025

	Contribution to LMP	
Line Limit Scenario for Violated Constraints	2024 (Jan - Sep)	2025 (Jan - Sep)
Line Limits Reduced by PJM (Actual)	$3.23	$5.31
Hypothetical Use of Full Line Limits	$0.02	$0.03
Change in Contribution to LMP	($3.21)	($5.27)
Percent Change in Contribution to LMP	(99.4%)	(99.4%)

Table 3-60 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 2025, there were 16,739, or 90 percent, violated transmission constraint intervals, which includes 1,032 violated transmission constraint intervals with actual line limits and 15,707 violated transmission constraint intervals with reduced line limits, in the real-time market with a transmission penalty factor equal to the default $2,000 per MWh.

94 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 3-60 Frequency of changes to the magnitude of transmission penalty factor (constraint intervals) in the real-time market: January through September, 2024 and 2025

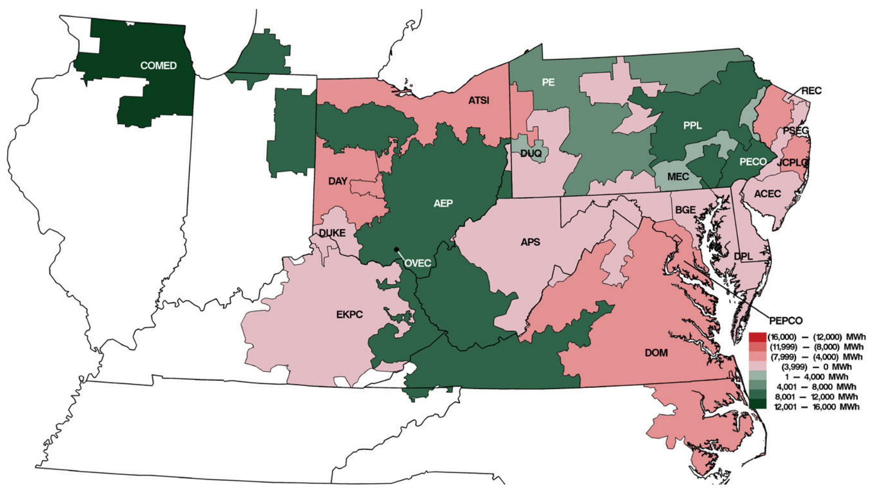
	2024 (Jan - Sep)			2025 (Jan - Sep)		
Description	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh
Violated Transmission Constraints (Actual)	96	-	345	1,032	-	1,741
Violated Transmission Constraints (Reduced)	9,215	-	105	15,707	-	17
Binding Transmission Constraints	99,470	-	201	102,497	-	2,485
Market to Market Transmission Constraints	5,811	17	34,814	8,703	19	26,625
All Transmission Constraints	114,592	17	35,465	127,939	19	30,868

Prior to September 1, 2022, transmission constraint penalty factors frequently set prices when PJM modeled a stability 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 uses a generator output limit constraint to manage generator voltage instability issues. In the first nine months of 2025, there were 11,264 constraint 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.

Net Generation by Zone

Figure 3-47 shows the difference between the PJM real-time generation and real-time load by zone for the first nine months of 2025. Figure 3-47 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 3-61 shows the difference between the real-time generation and real-time load by zone for the first nine months of 2024 and 2025.

Figure 3-47 Map of real-time generation less real-time load by zone: January through September, 2025[95]



95 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 3-61 Real-time generation less real-time load by zone (GWh): January through September, 2024 and 2025

	Zonal Generation and Load (GWh)					
	2024 (Jan-Sep)			2025 (Jan-Sep)		
Zone	Generation	Load	Net	Generation	Load	Net
ACEC	1,267	7,578	(6,311)	632	7,491	(6,859)
AEP	118,845	96,745	22,100	124,054	102,527	21,527
APS	38,722	36,166	2,557	37,656	36,912	744
ATSI	41,609	50,204	(8,595)	40,512	50,593	(10,081)
BGE	12,880	22,983	(10,104)	12,929	23,008	(10,078)
COMED	103,850	69,542	34,308	106,540	71,211	35,329
DAY	1,589	13,028	(11,439)	2,184	13,306	(11,122)
DUKE	9,780	20,042	(10,262)	10,559	20,234	(9,674)
DOM	81,867	91,934	(10,066)	85,191	98,947	(13,756)
DPL	3,938	13,947	(10,009)	4,334	14,153	(9,819)
DUQ	11,882	10,244	1,638	12,722	9,938	2,784
EKPC	7,248	10,428	(3,180)	8,414	10,690	(2,277)
JCPLC	6,349	16,795	(10,446)	6,545	16,623	(10,077)
MEC	13,393	11,416	1,977	15,090	11,339	3,751
OVEC	7,041	86	6,955	8,326	84	8,241
PECO	56,999	29,197	27,802	56,936	29,221	27,715
PE	21,497	12,527	8,969	23,737	12,260	11,477
PEPCO	8,142	21,231	(13,089)	9,086	21,357	(12,271)
PPL	57,649	30,038	27,611	58,098	30,545	27,553
PSEG	32,922	32,551	371	32,448	32,196	252
REC	0	1,099	(1,099)	0	1,085	(1,085)

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 3-62 shows PJM generation by fuel source in GWh for the first nine months of 2024 and 2025.

In the first nine months of 2025, generation from coal units increased 16.1 percent, generation from natural gas units decreased 1.6 percent, generation from oil units increased 25.8 percent, generation from wind units increased 1.8 percent, and generation from solar units increased 46.4 percent compared to the first nine months of 2024.

Table 3-62 Generation (By fuel source (GWh)): January through September, 2024 and 2025[96 97]

	2024 (Jan-Sep)		2025 (Jan-Sep)		Change in
	GWh	Percent	GWh	Percent	Output
Coal	95,995.4	14.8%	111,408.4	16.7%	16.1%
Bituminous	83,607.3	12.9%	93,212.5	14.0%	11.5%
Sub Bituminous	7,668.9	1.2%	12,837.2	1.9%	67.4%
Other Coal	4,719.3	0.7%	5,358.7	0.8%	13.5%
Nuclear	203,815.3	31.5%	204,130.4	30.7%	0.2%
Gas	291,909.4	45.1%	287,121.7	43.1%	(1.6%)
Natural Gas CC	263,984.9	40.8%	256,754.7	38.6%	(2.7%)
Natural Gas CT	16,536.3	2.6%	17,712.2	2.7%	7.1%
Natural Gas Other Units	10,525.8	1.6%	11,853.6	1.8%	12.6%
Other Gas	862.3	0.1%	801.2	0.1%	(7.1%)
Hydroelectric	13,092.2	2.0%	12,696.9	1.9%	(3.0%)
Pumped Storage	5,188.7	0.8%	5,295.3	0.8%	2.1%
Run of River	6,264.7	1.0%	5,886.6	0.9%	(6.0%)
Other Hydro	1,638.8	0.3%	1,515.0	0.2%	(7.6%)
Wind	21,814.7	3.4%	22,209.4	3.3%	1.8%
Waste	2,936.2	0.5%	2,926.0	0.4%	(0.3%)
Oil	3,287.4	0.5%	4,136.1	0.6%	25.8%
Heavy Oil	119.8	0.0%	183.8	0.0%	53.4%
Light Oil	1,840.3	0.3%	2,549.8	0.4%	38.6%
Diesel	24.6	0.0%	107.1	0.0%	335.9%
Other Oil	1,302.8	0.2%	1,295.4	0.2%	(0.6%)
Solar	13,913.5	2.1%	20,375.1	3.1%	46.4%
Battery	38.0	0.0%	50.4	0.0%	32.6%
Biofuel	997.9	0.2%	931.6	0.1%	(6.6%)
Total	647,800.1	100.0%	665,986.1	100.0%	2.8%

96 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.
97 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 3-63 Monthly generation (By fuel source (GWh)): January through September, 2025

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Coal	18,584.7	12,714.7	9,375.7	9,538.0	8,603.3	13,359.0	17,631.6	12,981.8	8,619.7	111,408.4
Bituminous	15,606.7	10,857.9	7,860.0	7,909.4	7,006.1	11,232.4	14,629.5	10,960.9	7,149.6	93,212.5
Sub Bituminous	2,557.3	1,202.1	844.0	978.9	1,049.4	1,508.7	2,385.8	1,338.8	972.2	12,837.2
Other Coal	420.7	654.6	671.7	649.7	547.7	617.9	616.4	682.1	497.9	5,358.7
Nuclear	25,031.1	21,749.3	21,593.7	20,300.6	21,890.2	23,429.7	23,878.6	23,982.7	22,274.5	204,130.4
Gas	33,699.7	30,340.4	27,994.5	23,473.1	25,932.2	33,888.3	41,588.9	37,031.7	33,172.9	287,121.7
Natural Gas CC	30,743.0	28,555.0	26,549.2	20,085.1	24,006.2	29,429.0	34,787.3	32,711.1	29,888.8	256,754.7
Natural Gas CT	1,678.0	1,161.2	1,071.8	2,018.1	929.9	2,357.1	3,904.6	2,434.6	2,156.9	17,712.2
Natural Gas Other Units	1,193.1	550.2	292.3	1,287.3	917.1	2,007.8	2,767.3	1,788.4	1,050.1	11,853.6
Other Gas	85.7	74.1	81.1	82.6	79.0	94.4	129.7	97.6	77.0	801.2
Hydroelectric	1,197.5	1,221.5	1,601.9	1,272.6	1,730.5	1,881.7	1,731.0	1,181.3	878.9	12,696.9
Pumped Storage	507.4	512.6	512.9	452.1	548.2	722.9	813.1	690.6	535.5	5,295.3
Run of River	560.4	577.8	960.4	698.2	1,053.1	930.2	646.0	279.7	180.9	5,886.6
Other Hydro	129.7	131.1	128.7	122.3	129.1	228.5	272.0	211.0	162.5	1,515.0
Wind	3,907.9	3,085.7	4,259.4	3,256.9	2,656.6	1,776.2	1,088.0	1,119.9	1,058.9	22,209.4
Waste	332.5	303.5	309.3	329.9	347.3	303.4	348.5	348.2	303.3	2,926.0
Oil	668.6	303.8	183.2	306.9	268.4	570.3	914.6	478.4	441.9	4,136.1
Heavy Oil	77.1	2.8	0.0	7.2	3.5	33.5	34.6	22.3	2.8	183.8
Light Oil	379.3	158.1	86.9	139.2	104.5	393.9	688.3	273.2	326.4	2,549.8
Diesel	50.6	1.5	1.6	1.4	0.7	19.5	16.1	12.6	3.2	107.1
Other Oil	161.6	141.5	94.6	159.1	159.8	123.4	175.6	170.2	109.5	1,295.4
Solar	1,261.4	1,308.6	2,120.4	2,397.3	2,408.1	2,804.2	2,966.1	2,792.1	2,316.9	20,375.1
Battery	5.9	5.0	5.3	5.3	5.5	5.2	5.7	6.6	5.9	50.4
Biofuel	123.7	123.5	72.8	86.1	69.5	111.1	125.0	141.0	78.9	931.6
Total	84,813.1	71,156.0	67,516.2	60,966.6	63,911.5	78,129.2	90,278.2	80,063.6	69,151.7	665,986.1

Table 3-64 shows the difference between the day-ahead and the real-time average generation by fuel source.

Table 3-64 Day-ahead and real-time average generation (By fuel source (GWh)): January through September, 2025

	2025 (Jan -Sep)					
	Day-Ahead		Real-Time			Percent
	GWh	Percent	GWh	Percent	RT - DA	Difference
Coal	111,492.0	17.3%	111,408.4	16.7%	(83.6)	(0.1%)
Bituminous	93,258.8	14.5%	93,212.5	14.0%	(46.2)	(0.0%)
Sub Bituminous	13,207.6	2.0%	12,837.2	1.9%	(370.4)	(2.8%)
Other Coal	5,025.6	0.8%	5,358.7	0.8%	333.0	6.6%
Nuclear	201,065.7	31.2%	204,130.4	30.7%	3,064.7	1.5%
Gas	279,048.9	43.3%	287,121.7	43.1%	8,072.8	2.9%
Natural Gas CC	252,907.9	39.2%	256,754.7	38.6%	3,846.8	1.5%
Natural Gas CT	13,550.4	2.1%	17,712.2	2.7%	4,161.8	30.7%
Natural Gas Other Units	11,792.7	1.8%	11,853.6	1.8%	61.0	0.5%
Other Gas	798.0	0.1%	801.2	0.1%	3.2	0.4%
Hydroelectric	12,135.2	1.9%	12,696.9	1.9%	561.7	4.6%
Pumped Storage	6,420.4	1.0%	5,295.3	0.8%	(1,125.1)	(17.5%)
Run of River	5,714.7	0.9%	5,886.6	0.9%	171.9	3.0%
Other Hydro	0.0	0.0%	1,515.0	0.2%	1,515.0	NA
Wind	16,200.6	2.5%	22,209.4	3.3%	6,008.8	37.1%
Waste	2,872.0	0.4%	2,926.0	0.4%	54.1	1.9%
Oil	3,657.5	0.6%	4,136.1	0.6%	478.7	13.1%
Heavy Oil	103.8	0.0%	183.8	0.0%	80.0	77.0%
Light Oil	2,295.5	0.4%	2,549.8	0.4%	254.3	11.1%
Diesel	31.5	0.0%	107.1	0.0%	75.6	239.6%
Other Oil	1,226.6	0.2%	1,295.4	0.2%	68.8	5.6%
Solar	17,527.6	2.7%	20,375.1	3.1%	2,847.5	16.2%
Battery	16.4	0.0%	50.4	0.0%	34.0	207.8%
Biofuel	1,002.3	0.2%	931.6	0.1%	(70.7)	(7.1%)
Total	645,018.1	100.0%	665,986.1	100.0%	20,968.1	3.3%

Table 3-65 shows the share of generation by natural gas, coal, nuclear and other fuel types in the real-time energy market since 2014.

Table 3-65 Share of generation by fuel source: January through September, 2014 through 2025

Jan - Sep	Natural Gas	Coal	Nuclear	Solar	Wind	Other Fuel Type
2014	17.0%	41.6%	36.6%	0.1%	1.8%	3.0%
2015	19.7%	38.6%	37.1%	0.1%	1.8%	2.8%
2016	24.1%	34.4%	36.5%	0.1%	2.0%	2.9%
2017	24.5%	31.7%	37.9%	0.2%	2.4%	3.3%
2018	29.5%	28.9%	35.1%	0.3%	2.4%	3.8%
2019	34.4%	25.1%	34.3%	0.3%	2.7%	3.3%
2020	40.0%	19.2%	34.2%	0.4%	2.9%	3.2%
2021	36.8%	24.0%	32.2%	0.9%	3.0%	3.1%
2022	39.6%	20.9%	31.9%	1.2%	3.4%	3.0%
2023	44.5%	15.0%	32.8%	1.4%	3.2%	3.1%
2024	44.9%	14.8%	31.5%	2.1%	3.4%	3.3%
2025	43.0%	16.7%	30.7%	3.1%	3.3%	3.2%

Fuel Diversity

Figure 3-48 shows the fuel diversity index (FDI_e) for PJM energy generation.[98] 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 3-62 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 27.9 percent from 2012 through September 2025. 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.[99] The increasing trend 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 16.8 percent for the first nine months of 2025. Gas generation as a share of total generation was 7.7 percent for the first nine months of 2008 and 42.8 percent for the first nine months of 2025. Wind and solar generation as a share of total generation was 0.4 percent for the first nine months of 2008 and 6.5 percent for the first nine months of 2025.

The FDI_e increased 2.5 percent in the first nine months of 2025 compared to the first nine months of 2024. Increased coal generation in the first nine months of 2025 and less generation from gas fired generators led to the increase in the FDI_e.

The FDI_e was also used to measure the impact on fuel diversity of potential retirements in 2025 through 2030. A total of 34,733 MW of capacity are at risk of retirement, consisting of 4,684 MW currently planning to retire, 16,786 MW expected to retire for regulatory reasons and 13,264 MW expected to be uneconomic.[100] This capacity consists primarily of coal steam plants and CTs. The units expected to retire by the end of 2025 generated 34,394.2 GWh in the first nine months of 2025. The dashed line (green) in Figure 3-48 shows a counterfactual result for FDI_e assuming the 34,394.2 GWh of generation from uneconomic units and expected 2025 retirements were replaced by gas, wind and solar generation.[101] The FDI_e for the first nine months of 2025 under this counterfactual assumption would have been 1.6 percent lower than the actual FDI_e. The units expected to retire by the end of 2030 generated 65,235.4 GWh in the first nine months of 2025. Replacing this generation with gas, wind and solar generation results in a counterfactual FDI_e that is 1.2 percent lower than the actual FDI_e.[102] The dashed line (blue) in Figure 3-48 shows a counterfactual

98 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.

99 See the *2019 Annual State of the Market Report for PJM*, 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.

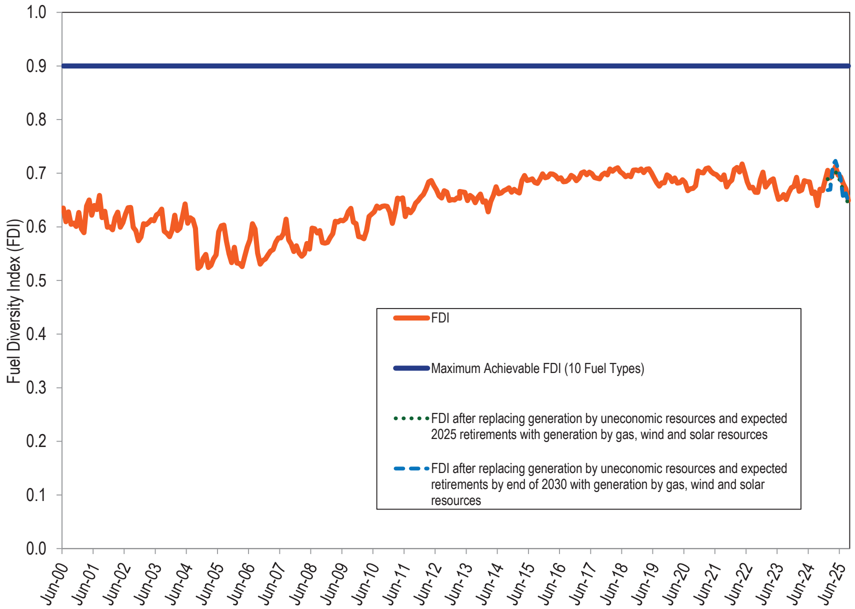
100 See Units At Risk of Retirement in the *2024 Annual State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

101 It is assumed that 8,962.7 GWh of the replacement energy will be from new wind and solar units. This value represents the increase over 2025 levels in renewable generation that is required by RPS in 2026. The split between solar (78.9 percent) and wind (21.1 percent) is based on queue data and 2025 capacity factors in Table 8-33 and Table 8-37.

102 It is assumed that 33,840.5 GWh of the replacement energy will be from new wind and solar units. This value represents the increase over 2025 levels in renewable generation that is required by RPS in 2030. The split between solar (78.9 percent) and wind (21.1 percent) is based on queue data and 2025 capacity factors in Table 8-33 and Table 8-37.

result for FDI_e assuming that this generation is replaced with gas, wind and solar generation.

Figure 3-48 Fuel diversity index for monthly generation: June 2000 through September 2025



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. 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 3-66 shows the approved nomination deadlines and corresponding start time of gas flow.[103] Pipelines provide that firm service requests may replace, or bump, interruptible nominations on the pipeline under defined conditions.

Table 3-66 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 2024 and 2025, 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

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

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, 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 highlight 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 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 significantly 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 3-66. 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 3-67 shows the notification time gas fired generators should be requesting and submitting when pipelines require nominating per the NAESB cycle deadlines.

Table 3-67 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 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.[104] The resultant guidelines were posted by the MMU and PJM on September 8, 2023.[105]

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 3-68 shows the type of fuel used and technology by marginal resources in the real-time energy market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first nine months of 2025, coal units were 7.6 percent and natural gas units were 77.9 percent of marginal resources. In the first nine months of 2025, natural gas combined cycle units were 63.8 percent of marginal resources. In the first nine months of 2024, coal units were 11.0 percent and natural gas units were 74.8 percent of the total marginal resources. In the first nine months of 2024, natural gas combined cycle units were 61.5 percent of the total marginal resources. In the first nine months of 2025, 68.7 percent of the wind marginal units had negative offer prices, 30.2 percent had zero offer prices and 1.1 percent of the wind marginal units had positive offer prices. In the first nine months of 2024, 49.2 percent of the wind marginal units had negative offer prices, 40.7 percent had zero offer prices and 10.0 percent had positive offer prices.

The proportion of marginal nuclear units decreased from 0.35 percent in the first nine months of 2024 to 0.11 percent in the first nine months of 2025. Most nuclear units are offered as fixed generation in the PJM market. A small number of nuclear units have been 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 3-68 are from the pricing run, which may not be the same as marginal resources from the dispatch run.

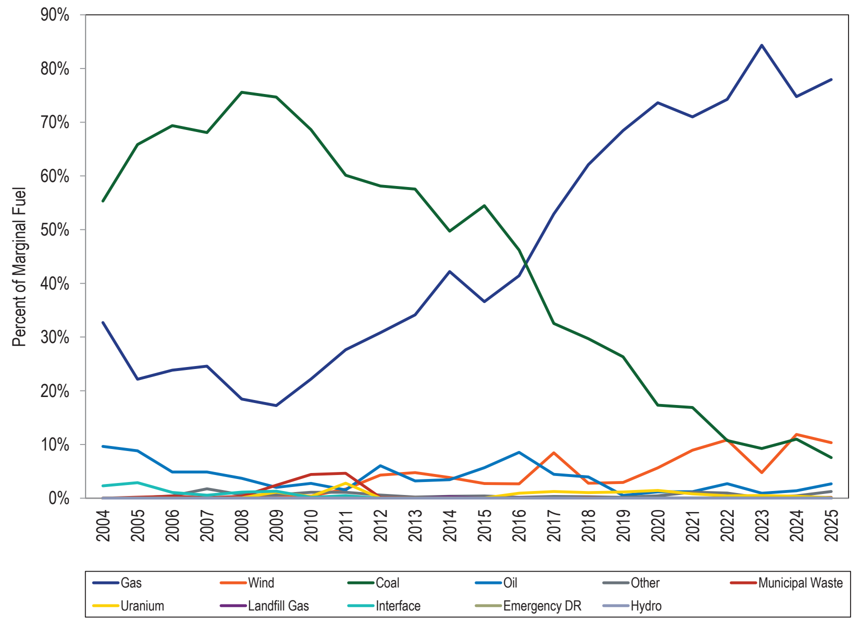
104 "Gas Nomination Cycles and Units Operating Parameters," Electric Gas Coordination Senior Task Force (EGCSTF), August 15, 2023.
105 *See* Guidelines posted by the MMU and PJM: Temporary Operating Parameter Limit (PLS) Exceptions due to Pipeline Restrictions. <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Temporary_Operating_Parameter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

Table 3-68 Type of fuel used and technology (By real-time marginal units): January through September, 2021 through 2025[106]

		(Jan - Sep)				
Fuel	Technology	2021	2022	2023	2024	2025
Gas	CC	60.86%	60.40%	71.16%	61.48%	63.88%
Gas	CT	8.52%	11.53%	10.24%	9.99%	10.56%
Wind	Wind	8.93%	10.86%	4.75%	11.87%	10.34%
Coal	Steam	16.90%	10.73%	9.26%	11.01%	7.56%
Gas	Steam	1.07%	1.46%	1.78%	2.67%	2.55%
Oil	CT	1.06%	2.61%	0.52%	1.11%	1.58%
Other	Solar	1.04%	0.90%	0.01%	0.39%	1.16%
Oil	RICE	0.05%	0.04%	0.07%	0.07%	0.93%
Gas	RICE	0.53%	0.87%	1.15%	0.64%	0.93%
Uranium	Steam	0.81%	0.45%	0.51%	0.35%	0.11%
Oil	Steam	0.09%	0.02%	0.07%	0.19%	0.08%
Municipal Waste	RICE	0.00%	0.00%	0.06%	0.09%	0.08%
Municipal Waste	Steam	0.01%	0.03%	0.10%	0.07%	0.07%
Other	Steam	0.10%	0.05%	0.05%	0.06%	0.07%
Oil	CC	0.03%	0.04%	0.27%	0.02%	0.07%
Other	Battery	0.00%	0.00%	0.00%	0.01%	0.01%
Landfill Gas	CT	0.01%	0.00%	0.00%	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%

Figure 3-49 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 3-49 Type of fuel used (By real-time marginal units): January through September, 2004 through 2025



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

Table 3-69 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 2025. In the first nine months of 2025, marginal fast start resources accounted for 7.91 percent of all marginal resources in the pricing run.

Table 3-69 Fuel type and technology (Real-time marginal units and fast start marginal units): January through September, 2025

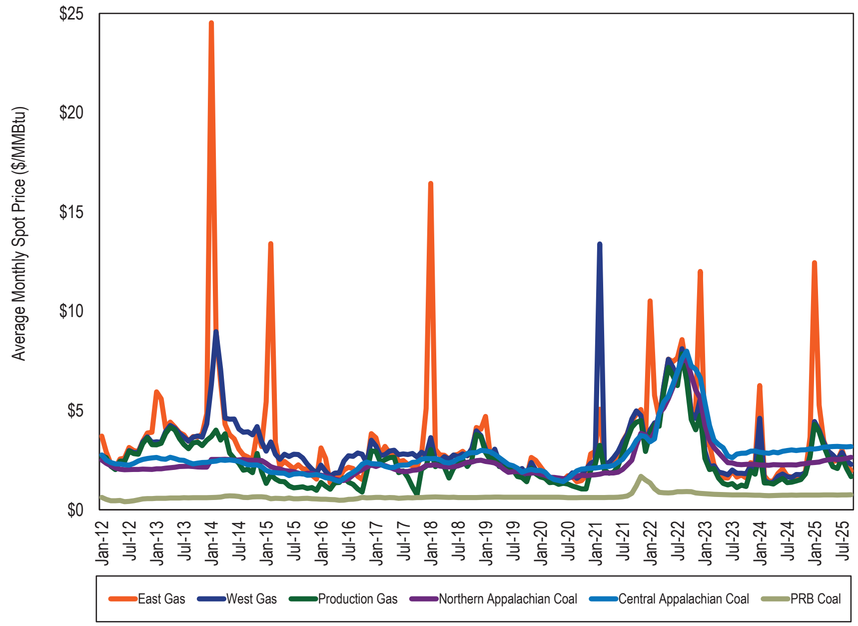
		2025 (Jan - Sep)		
Fuel	Technology	Fast Start	Other	Both
Coal	Steam	0.00%	7.56%	7.56%
Gas	CC	0.00%	63.88%	63.88%
Gas	CT	5.29%	5.28%	10.56%
Gas	RICE	0.92%	0.01%	0.93%
Gas	Steam	0.00%	2.55%	2.55%
Landfill Gas	CT	0.00%	0.00%	0.00%
Municipal Waste	RICE	0.01%	0.07%	0.08%
Municipal Waste	Steam	0.00%	0.07%	0.07%
Oil	CC	0.00%	0.07%	0.07%
Oil	CT	0.63%	0.95%	1.58%
Oil	RICE	0.93%	0.00%	0.93%
Oil	Steam	0.00%	0.08%	0.08%
Other	Battery	0.00%	0.01%	0.01%
Other	Solar	0.04%	1.12%	1.16%
Other	Steam	0.00%	0.07%	0.07%
Uranium	Steam	0.00%	0.11%	0.11%
Wind	Wind	0.09%	10.25%	10.34%
All Marginal Units		7.91%	92.09%	100.00%

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 3-50 shows fuel prices in PJM for 2012 through September 2025. Natural gas prices and coal prices increased and oil prices decreased in the first nine months of 2025 compared to the first nine months of 2024. In the first nine months of 2025, the price of eastern natural gas was 83.4 percent higher and the price of western natural gas was 59.2 percent higher than in the first nine months of 2025. The price of Northern Appalachian coal was 11.4 percent higher; the price of Central Appalachian coal was 7.8 percent higher; and the price of Powder River Basin coal was 2.5 percent higher.[107] The price of ULSD NY Harbor Barge (ultra low sulfur diesel) was 6.4 percent lower in the first nine months of 2025 than in the first nine months of 2024.

Figure 3-50 Spot average fuel price comparison: 2012 through September 2025 ($/MMBtu)



107 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, and New Jersey.[108] 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 pricing run solution does not meet the reserve requirements, PJM invokes shortage pricing, based on the operating reserve demand curve. During shortage conditions, the LMPs of marginal generators reflect the cost of not meeting the reserve requirements, the scarcity component, which is defined by the operating reserve demand curve.[109]

Starting on September 1, 2021, the components shown in Table 3-70 and Table 3-72 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 3-70, including markup using unadjusted cost-based offers.[110] Table 3-70 shows that in the first nine months of 2025, 7.2 percent of the load-weighted LMP was the result of coal costs, 43.4 percent was the result of gas costs and 4.1 percent was the result of the cost of carbon emission allowances. 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. Using unadjusted cost-based offers, negative markup was -7.4 percent of the load-weighted LMP. Using unadjusted cost-based offers, positive markup was 7.2 percent of the load-weighted LMP. LMP may, at times, be set by transmission constraint penalty factors. In the first nine months of 2025, 10.5 percent of the load-weighted LMP was the result of transmission penalty factors. More than 99 percent of this impact occurred as a result of PJM's reduction to line ratings in SCED. The percent contribution of transmission penalty factors has increased substantially since PJM allowed penalty factors to affect LMPs starting February 1, 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 2024 and 2025.

108 New Jersey withdrew from RGGI, effective January 1, 2012, and rejoined RGGI effective January 1, 2020. Virginia joined RGGI effective January 1, 2021, and left RGGI on December 31, 2023. Litigation over Virginia's participation is pending. See Virginia Court of Appeals (Case No. 1494-23-4).

109 Scarcity component includes ancillary service redispatch cost component during periods of scarcity.

110 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 3-70 Components of real-time (Unadjusted) load-weighted average LMP: January through September, 2024 and 2025

	2024 (Jan - Sep)		2025 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$13.00	37.9%	$21.94	43.4%	5.6%
Transmission Constraint Penalty Factor	$3.23	9.4%	$5.31	10.5%	1.1%
Positive Markup	$3.94	11.5%	$3.64	7.2%	(4.3%)
Coal	$4.17	12.1%	$3.62	7.2%	(5.0%)
Variable Maintenance	$3.28	9.6%	$3.46	6.8%	(2.7%)
Ten Percent Adder	$1.99	5.8%	$3.06	6.1%	0.3%
Oil	$1.08	3.1%	$2.66	5.3%	2.1%
CO_2 Cost	$1.91	5.6%	$2.08	4.1%	(1.4%)
NA	$0.11	0.3%	$1.46	2.9%	2.6%
Scarcity	$0.18	0.5%	$1.32	2.6%	2.1%
Variable Operations	$1.46	4.3%	$1.30	2.6%	(1.7%)
Ancillary Service Redispatch Cost	$1.41	4.1%	$1.21	2.4%	(1.7%)
Opportunity Cost Adder	$1.37	4.0%	$1.17	2.3%	(1.7%)
Emergency Demand Response	$0.00	0.0%	$0.89	1.8%	1.8%
Market-to-Market	$0.30	0.9%	$0.59	1.2%	0.3%
Increase Generation Differential	$0.24	0.7%	$0.50	1.0%	0.3%
LPA Rounding Difference	$0.20	0.6%	$0.38	0.8%	0.2%
Landfill Gas	$0.05	0.1%	$0.08	0.2%	0.0%
NO_x Cost	$0.11	0.3%	$0.07	0.1%	(0.2%)
Other	$0.02	0.1%	$0.02	0.0%	(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%
PJM Administrative Cap	$0.00	0.0%	($0.11)	(0.2%)	(0.2%)
Renewable Energy Credits	($0.05)	(0.1%)	($0.14)	(0.3%)	(0.1%)
Decrease Generation Differential	($0.05)	(0.1%)	($0.25)	(0.5%)	(0.3%)
Negative Markup	($3.64)	(10.6%)	($3.74)	(7.4%)	3.2%
Total	$34.31	100.0%	$50.51	100.0%	0.0%

Components of Change in LMP

Table 3-71 shows the components of the increase in real-time load-weighted average LMP from the first nine months of 2024 to the first nine months of 2025. In the first nine months of 2025, the real-time load-weighted average LMP increased by $16.20 per MWh, 47.2 percent. Fuel and consumables cost components of LMP (the sum of gas, coal, oil, landfill gas, variable operations) increased the LMP by $9.85 per MWh, 60.8 percent of increase in LMP. 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 $0.16 per MWh, -1.0 percent of the increase in LMP. The sum of the positive and negative markups, ten percent adder, and maintenance cost components, all of which reflect market power, increased the LMP $0.85 per MWh, 5.2 percent of the increase in LMP. The scarcity component increased the LMP by $1.14 per MWh, 7.0 percent of the increase in the LMP. The transmission constraint penalty factor increased the LMP by $2.07 per MWh, 12.8 percent, primarily as a result of PJM's reduction of line ratings in SCED. The ancillary service redispatch cost, the opportunity cost of reduced marginal generation to meet reserve requirements, decreased the LMP by $0.21 per MWh, -1.3 percent. The pre-emergency demand response called on by PJM during the hot weather days in June increased the LMP by $0.89 per MWh, 5.5 percent of the increase in LMP. The LMP increase would have been higher if PJM had not imposed a $3,700.00 per MWh administrative cap. The administrative cap reduced the LMP by $0.11 per MWh, a 0.7 percent decrease.

Table 3-71 Components of Change in real-time load-weighted average LMP: January through September, 2024 and 2025

Component	2024 (Jan - Sep)	2025 (Jan - Sep)	Change in LMP	Percent of Total Change
Fuel and Consumables	$19.75	$29.59	$9.85	60.8%
Emission Related	$3.34	$3.18	($0.16)	(1.0%)
Market Power Related	$5.57	$6.42	$0.85	5.2%
Scarcity	$0.18	$1.32	$1.14	7.0%
Transmission Constraint Penalty Factor	$3.23	$5.31	$2.07	12.8%
Ancillary Service Redispatch Cost	$1.41	$1.21	($0.21)	(1.3%)
Pre-emergency Demand Response	$0.00	$0.89	$0.89	5.5%
PJM Administrative Cap	$0.00	($0.11)	($0.11)	(0.7%)
All Other	$0.82	$2.71	$1.89	11.6%
Total Change	$34.31	$50.51	$16.20	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 3-70) markup is the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-72), the 10 percent markup is removed from the cost-based offers of coal, gas, and oil units (adjusted markup).

Table 3-72 Components of real-time (Adjusted) load-weighted average LMP: January through September, 2024 and 2025

	2024 (Jan - Sep)		2025 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$13.00	37.9%	$21.94	43.4%	5.6%
Positive Markup	$4.90	14.3%	$5.43	10.7%	(3.5%)
Transmission Constraint Penalty Factor	$3.23	9.4%	$5.31	10.5%	1.1%
Coal	$4.17	12.1%	$3.62	7.2%	(5.0%)
Variable Maintenance	$3.28	9.6%	$3.46	6.8%	(2.7%)
Oil	$1.08	3.1%	$2.66	5.3%	2.1%
CO_2 Cost	$1.91	5.6%	$2.08	4.1%	(1.4%)
NA	$0.11	0.3%	$1.46	2.9%	2.6%
Scarcity	$0.18	0.5%	$1.32	2.6%	2.1%
Variable Operations	$1.46	4.3%	$1.30	2.6%	(1.7%)
Ancillary Service Redispatch Cost	$1.41	4.1%	$1.21	2.4%	(1.7%)
Opportunity Cost Adder	$1.37	4.0%	$1.17	2.3%	(1.7%)
Emergency Demand Response	$0.00	0.0%	$0.89	1.8%	1.8%
Market-to-Market	$0.30	0.9%	$0.59	1.2%	0.3%
Increase Generation Differential	$0.24	0.7%	$0.50	1.0%	0.3%
LPA Rounding Difference	$0.20	0.6%	$0.38	0.8%	0.2%
Landfill Gas	$0.05	0.1%	$0.08	0.2%	0.0%
NO_x Cost	$0.11	0.3%	$0.07	0.1%	(0.2%)
Other	$0.02	0.1%	$0.02	0.0%	(0.0%)
Ten Percent Adder	$0.01	0.0%	$0.01	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
LPA-SCED Differential	($0.00)	(0.0%)	($0.00)	(0.0%)	0.0%
PJM Administrative Cap	$0.00	0.0%	($0.11)	(0.2%)	(0.2%)
Renewable Energy Credits	($0.05)	(0.1%)	($0.14)	(0.3%)	(0.1%)
Decrease Generation Differential	($0.05)	(0.1%)	($0.25)	(0.5%)	(0.3%)
Negative Markup	($2.62)	(7.6%)	($2.48)	(4.9%)	2.7%
Total	$34.31	100.0%	$50.51	100.0%	0.0%

The components of LMP for the dispatch run and the pricing run are shown in Table 3-73, including markup using unadjusted cost-based offers for in the first nine months of 2025. The variable maintenance cost component is the component with the largest change in the share of total LMP from the dispatch run to the pricing run is, constituting 4.5 percent of the dispatch run LMP and 6.8 percent of the pricing run LMP.

Table 3-73 Comparison of components of real-time (Unadjusted) load-weighted average LMP in the dispatch run and pricing run: January through September, 2025

	Dispatch		Pricing		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$20.45	44.1%	$21.94	43.4%	(0.7%)
Transmission Constraint Penalty Factor	$5.25	11.3%	$5.31	10.5%	(0.8%)
Positive Markup	$3.34	7.2%	$3.64	7.2%	0.0%
Coal	$4.08	8.8%	$3.62	7.2%	(1.6%)
Variable Maintenance	$2.10	4.5%	$3.46	6.8%	2.3%
Ten Percent Adder	$2.75	5.9%	$3.06	6.1%	0.1%
Oil	$1.93	4.2%	$2.66	5.3%	1.1%
CO_2 Cost	$2.08	4.5%	$2.08	4.1%	(0.4%)
NA	$1.42	3.1%	$1.46	2.9%	(0.2%)
Scarcity	$1.04	2.2%	$1.32	2.6%	0.4%
Variable Operations	$1.28	2.8%	$1.30	2.6%	(0.2%)
Ancillary Service Redispatch Cost	$0.75	1.6%	$1.21	2.4%	0.8%
Opportunity Cost Adder	$1.08	2.3%	$1.17	2.3%	(0.0%)
Emergency Demand Response	$0.95	2.0%	$0.89	1.8%	(0.3%)
Market-to-Market	$0.51	1.1%	$0.59	1.2%	0.1%
Increase Generation Differential	$0.50	1.1%	$0.50	1.0%	(0.1%)
LPA Rounding Difference	$0.27	0.6%	$0.38	0.8%	0.2%
Landfill Gas	$0.09	0.2%	$0.08	0.2%	(0.0%)
NO_x Cost	$0.06	0.1%	$0.07	0.1%	0.0%
Other	$0.02	0.0%	$0.02	0.0%	(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%
PJM Administrative Cap	$0.00	0.0%	($0.11)	(0.2%)	(0.2%)
Renewable Energy Credits	($0.15)	(0.3%)	($0.14)	(0.3%)	0.1%
Decrease Generation Differential	($0.21)	(0.5%)	($0.25)	(0.5%)	(0.0%)
Negative Markup	($3.23)	(7.0%)	($3.74)	(7.4%)	(0.4%)
Total	$46.34	100.0%	$50.51	100.0%	0.0%

The components of the total cost to real-time load ($M) are shown in Table 3-74, including markup using unadjusted cost-based offers. The components of the total cost to real-time load are shown in Table 3-75, including markup using adjusted cost-based offers. In the first nine months of 2025, the cost of real-time load increased by $10,488.1 million or 51.1 percent. Of the $30,996.6 million in the total cost of real-time load in the first nine months of 2025, $13,463.2 million is due to the cost of gas, $3,255.9 million is due to the transmission penalty factor, $2,234.5 million is due to the positive markup, $2,218.7 million is due to the cost of coal, $2,122.1 million is due to the variable maintenance and $1,876.2 million is due to the ten percent adder.

Table 3-74 Components of the cost of real-time (Unadjusted) load: January through September, 2024 and 2025

	Contribution to Real Time Cost of Load ($Million)			
Element	2024 (Jan - Sep)	2025 (Jan - Sep)	Change	Percent
Gas	$7,769.0	$13,463.2	$5,694.1	54.3%
Transmission Constraint Penalty Factor	$1,931.7	$3,255.9	$1,324.2	12.6%
Positive Markup	$2,357.3	$2,234.5	($122.8)	(1.2%)
Coal	$2,491.0	$2,218.7	($272.2)	(2.6%)
Variable Maintenance	$1,962.5	$2,122.1	$159.6	1.5%
Ten Percent Adder	$1,186.6	$1,876.2	$689.6	6.6%
Oil	$643.4	$1,631.6	$988.2	9.4%
CO_2 Cost	$1,141.0	$1,276.8	$135.8	1.3%
NA	$64.0	$897.7	$833.7	7.9%
Scarcity	$105.9	$809.5	$703.5	6.7%
Variable Operations	$873.1	$795.9	($77.2)	(0.7%)
Ancillary Service Redispatch Cost	$845.7	$739.7	($106.0)	(1.0%)
Opportunity Cost Adder	$817.7	$716.5	($101.1)	(1.0%)
Emergency Demand Response	$0.0	$545.0	$545.0	5.2%
Market-to-Market	$180.8	$364.1	$183.4	1.7%
Increase Generation Differential	$144.2	$307.6	$163.4	1.6%
LPA Rounding Difference	$121.6	$234.0	$112.4	1.1%
Landfill Gas	$27.1	$51.5	$24.4	0.2%
NO_x Cost	$67.0	$41.6	($25.5)	(0.2%)
Other	$10.9	$9.7	($1.2)	(0.0%)
SO_2 Cost	$0.2	$0.1	($0.1)	(0.0%)
LPA-SCED Differential	($0.0)	($0.0)	$0.0	0.0%
PJM Administrative Cap	$0.0	($68.0)	($68.0)	(0.6%)
Renewable Energy Credits	($27.0)	($83.9)	($56.9)	(0.5%)
Decrease Generation Differential	($29.4)	($151.0)	($121.6)	(1.2%)
Negative Markup	($2,175.7)	($2,292.3)	($116.6)	(1.1%)
Total	$20,508.5	$30,996.6	$10,488.1	100.0%

Table 3-75 Components of the (Adjusted) cost of real-time load: January through September, 2024 and 2025

	Contribution to Real Time Cost of Load ($Million)			
Element	2024 (Jan - Sep)	2025 (Jan - Sep)	Change	Percent
Gas	$7,769.0	$13,463.2	$5,694.1	54.3%
Positive Markup	$2,930.7	$3,331.7	$400.9	3.8%
Transmission Constraint Penalty Factor	$1,931.7	$3,255.9	$1,324.2	12.6%
Coal	$2,491.0	$2,218.7	($272.2)	(2.6%)
Variable Maintenance	$1,962.5	$2,122.1	$159.6	1.5%
Oil	$643.4	$1,631.6	$988.2	9.4%
CO_2 Cost	$1,141.0	$1,276.8	$135.8	1.3%
NA	$63.9	$897.5	$833.6	7.9%
Scarcity	$105.9	$809.5	$703.5	6.7%
Variable Operations	$873.1	$795.9	($77.2)	(0.7%)
Ancillary Service Redispatch Cost	$845.7	$739.7	($106.0)	(1.0%)
Opportunity Cost Adder	$817.7	$716.5	($101.1)	(1.0%)
Emergency Demand Response	$0.0	$545.0	$545.0	5.2%
Market-to-Market	$180.8	$364.1	$183.4	1.7%
Increase Generation Differential	$144.2	$307.6	$163.4	1.6%
LPA Rounding Difference	$121.6	$234.0	$112.4	1.1%
Landfill Gas	$27.1	$51.5	$24.4	0.2%
NO_x Cost	$67.0	$41.6	($25.5)	(0.2%)
Other	$10.9	$9.7	($1.2)	(0.0%)
Ten Percent Adder	$4.5	$6.9	$2.4	0.0%
SO_2 Cost	$0.2	$0.1	($0.1)	(0.0%)
LPA-SCED Differential	($0.0)	($0.0)	$0.0	0.0%
PJM Administrative Cap	$0.0	($68.0)	($68.0)	(0.6%)
Renewable Energy Credits	($27.0)	($83.9)	($56.9)	(0.5%)
Decrease Generation Differential	($29.4)	($151.0)	($121.6)	(1.2%)
Negative Markup	($1,567.1)	($1,520.1)	$47.0	0.4%
Total	$20,508.5	$30,996.6	$10,488.1	100.0%

Table 3-76 shows the components of the increase in the cost of real-time load from the first nine months of 2024 to the first nine months of 2025. In the first nine months of 2025, the cost of real-time load increased $10,488.1 million. Fuel and consumables cost components of LMP (the sum of gas, coal, oil, landfill gas, variable operations) increased the cost of real-time load by $6,357.3 million, 60.6 percent of the increase in the cost of real-time load. The emissions cost components (the sum of NO_X, CO_2, opportunity cost adder, SO_2, and renewable energy credits) decreased the real-time cost of load by $47.9 million, -0.5 percent of the increase in the cost of real-time load. The sum of the positive and negative markups, ten percent adder, and maintenance cost components, all of which reflect market power, increased the cost of real-time load by $609.8 million, 5.8 percent of the increase in the cost of real time load. The scarcity component increased the cost of real-time load by $703.5 million, 6.7 percent of the increase in the cost of real-time load. The transmission constraint penalty factor increased the cost of real-time load by $1,324.2 million, 12.6 percent. The ancillary service redispatch cost, the opportunity cost of reduced marginal generation to meet reserve requirements, decreased the cost of real-time load by $106.0, 1.0 percent of the cost of real time load. The emergency demand response called on by PJM during the hot weather days in June and July increased the cost of real time load by $545.0 million, 5.2 percent of the increase in the cost of real time load. The cost of real time load would have been higher if PJM had not imposed a $3,700.00 per MWh administrative cap on SMP. The administrative cap reduced the cost of real time load by $68.0 million, a 0.6 percent decrease.

Table 3-76 Components of Change in the cost of real-time load: January through September, 2024 and 2025

	($ Million)			
Component	2024 (Jan - Sep)	2025 (Jan - Sep)	Change	Percent of Total Change
Fuel and Consumables	$11,803.5	$18,160.8	$6,357.3	60.6%
Emission Related	$1,999.0	$1,951.1	($47.9)	(0.5%)
Market Power Related	$3,330.6	$3,940.4	$609.8	5.8%
Scarcity	$105.9	$809.5	$703.5	6.7%
Transmission Constraint Penalty Factor	$1,931.7	$3,255.9	$1,324.2	12.6%
Ancillary Service Redispatch Cost	$845.7	$739.7	($106.0)	(1.0%)
Pre-emergency Demand Response	$0.0	$545.0	$545.0	5.2%
PJM Administrative Cap	$0.0	($68.0)	($68.0)	(0.6%)
All Other	$492.0	$1,662.1	$1,170.1	11.2%
Total Change	$20,508.5	$30,996.6	$10,488.1	100.0%

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 2025, 12.2 percent of the load-weighted LMP was the result of gas costs, 7.2 percent of the load-weighted LMP was the result of coal costs, 18.3 percent was the result of INCs, 33.2 percent was the result of DECs, 4.0 percent was the result of UTCs, and 7.1 percent was the result of positive markup.[111]

Table 3-77 Components of day-ahead (Unadjusted) load-weighted average LMP (Dollars per MWh): April through September, 2025

	2025 (Apr - Sep)	
Element	Contribution to LMP	Percent
DEC	$15.92	33.2%
INC	$8.79	18.3%
Gas	$5.86	12.2%
NA	$5.07	10.6%
Coal	$3.46	7.2%
Positive Markup	$3.39	7.1%
Up to Congestion	$1.92	4.0%
Variable Maintenance	$1.20	2.5%
Ten Percent Adder	$1.12	2.3%
Variable Operations	$0.88	1.8%
Ancillary Service Redispatch Cost	$0.79	1.6%
CO_2 Cost	$0.69	1.4%
Oil	$0.32	0.7%
Increase Generation Differential	$0.13	0.3%
Opportunity Cost Adder	$0.07	0.1%
NO_x Cost	$0.05	0.1%
Other	$0.01	0.0%
SO_2 Cost	$0.00	0.0%
Landfill Gas	$0.00	0.0%
Decrease Generation Differential	($0.00)	(0.0%)
Scarcity	($0.01)	(0.0%)
Transmission Constraint Penalty Factor	($0.02)	(0.0%)
Negative Markup	($0.76)	(1.6%)
Renewable Energy Credits	($0.88)	(1.8%)
Total	$48.00	100.0%

111 MMU identified an error in the marginal resource identification algorithm within the day ahead clearing optimization. The calculation of generator sensitivity factors requires accurate identification of marginal resources. The error was fixed by the PJM software vendor in March 2025. MMU was unable to calculate the component breakdown for 2024 and the first quarter of 2025 due to the inaccurate identification of marginal resources.

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.[112]

Table 3-78 Components of day-ahead (Adjusted) load-weighted average LMP (Dollars per MWh): April through September, 2025

	2025 (Apr - Sep)	
Element	Contribution to LMP	Percent
DEC	$15.92	33.2%
INC	$8.79	18.3%
Gas	$5.86	12.2%
NA	$5.07	10.6%
Positive Markup	$4.07	8.5%
Coal	$3.46	7.2%
Up to Congestion	$1.92	4.0%
Variable Maintenance	$1.20	2.5%
Variable Operations	$0.88	1.8%
Ancillary Service Redispatch Cost	$0.79	1.6%
CO_2 Cost	$0.69	1.4%
Oil	$0.32	0.7%
Increase Generation Differential	$0.13	0.3%
Opportunity Cost Adder	$0.07	0.1%
NO_x Cost	$0.05	0.1%
Other	$0.01	0.0%
Ten Percent Adder	$0.00	0.0%
SO_2 Cost	$0.00	0.0%
Landfill Gas	$0.00	0.0%
Decrease Generation Differential	($0.00)	(0.0%)
Scarcity	($0.01)	(0.0%)
Transmission Constraint Penalty Factor	($0.02)	(0.0%)
Negative Markup	($0.31)	(0.7%)
Renewable Energy Credits	($0.88)	(1.8%)
Total	$48.00	100.0%

112 Id.

Shortage

PJM's real-time energy market experienced five-minute shortage pricing for one or more reserve products for 130 unique five-minute intervals across 22 days in the first nine months of 2025. PJM implemented fast start pricing on September 1, 2021, creating the possibility that the pricing run and the dispatch run could classify different intervals as short. In the first nine months of 2025, there were 130 unique five-minute intervals with real-time shortage pricing in the pricing run for one or more reserve products, and 111 unique intervals with real-time shortage pricing in the dispatch run for one or more reserve products.

Emergency Procedures

PJM issues advisories usually several days in advance to notify members of possible emergency actions that could be taken during the operating day. PJM declares alerts at least a day prior to the operating day to notify 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.

Some emergency actions serve as triggers for performance assessment intervals (PAIs) when declared for the RTO or the active subzone. Some emergency actions trigger PAIs unconditionally while others only trigger PAIs when there is a primary reserve shortage for that area.[113] [114] The declaration of such emergency actions for smaller areas, such as for specific control zones, does not trigger a PAI. When communicating emergency procedures, PJM will also post NERC energy emergency alert (EEA) levels.[115] Table 3-79 provides a

113 See PJM. "PJM Manual 18: PJM Capacity Market," § 8.4A Non-Performance Assessment, Rev. 61 (Jul. 23, 2025).
114 OATT, Part I (Common Service Provisions) § 1.
115 NERC Attachment 1-EOP-011-4. "Energy Emergency Alerts," February 15, 2024. <https://www.nerc.com/pa/Stand/Reliability%20 Standards/EOP-011-4.pdf>.

description of PJM declared emergency procedures, in alphabetical order, including whether they are a trigger for PAIs and the NERC EEA level triggered with the procedure, if any.[116] [117] [118] [119]

Table 3-79 Description of emergency procedures

Emergency Procedure	Priority Level	Triggers NERC Energy Emergency Alert	Triggers Performance Assessment Interval	Purpose
Cold Weather Advisory	Advisory			To notify personnel and facilities that PJM may issue a Cold Weather Alert.
Cold Weather Alert	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.
Conservative Operations	Alert			To notify personnel and facilities that PJM may operate more conservatively. This can be due to natural phenomena, weather events, security events, and other conditions. Conservative operations may result in the use of larger contingencies and stricter transfer limits.
Emergency Energy Bids Requested	Informational			To request bids for emergency energy after declaring a Maximum Emergency Generation Action.
Emergency Mandatory Load Management Reduction Action	Action	EEA2		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)
Geomagnetic Disturbance Action	Action			To inform members that PJM will operate the grid with more conservative transfer limits developed for such disturbances. Transmission owners must coordinate with PJM before acting upon their own disturbance procedures.
Geomagnetic Disturbance Warning	Warning			To warn members than the National Oceanic and Atmospheric Administration predict a possible geomagnetic storm of severity K7 or greater, which can induce currents in the system and equipment.
High System Voltage Action	Action			To prepare the system for possible high voltages and to coordinate with transmission owners and generation owners for managing those high voltages.
Hot Weather Alert	Alert			To prepare personnel and facilities for extreme hot and/or humid weather conditions, generally when forecast temperatures exceed 90 degrees with high humidity.
Load Shed Directive	Action		Yes	To shed load in a local area, reserve subzone, or the entire RTO. A load shed directive for the reserve subzone or the entire RTO triggers a Performance Assessment Interval.
Low Voltage Alert	Alert			To alert transmission owners and generation owners that a period of low voltage and high load are expected.
Maintenance Outage Recall	Informational			To request that generation owners make units available by canceling any maintenance outages within at least 72 hours of posting. After that time, maintenance outages are converted into forced outages.
Maximum Emergency Action	Action		Yes with PR shortage	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.
Maximum Emergency Generation Alert	Alert	EEA1		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.
Non-Market Post Contingency Local Load Relief Warning	Warning			To warn transmission owners of the possibility of load shed in their area for non-market facilities.
Post Contingency Local Load Relief Warning	Warning			To warn transmission owners of the possibility of load shed in their area.
Pre-Emergency Mandatory Load Management Reduction Action	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
Transmission Loading Relief (TLR)	Informational			To maintain transmission operating security limits. This can involve curtailing external transactions and charging outside customers for the cost of congestion.
Unit Startup Notification Alert	Alert			To direct generation owners to prepare units so that long lead time units can come online within 48 hours. This notice is given days in advance of the predicted need.
Voltage Reduction Action	Action	EEA2 or EEA3 depending on circumstance	Yes	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.

116 See PJM. "PJM Manual 13: Emergency Operations," § 3.3 Cold Weather Advisory / Alert, Rev. 94 (Dec. 18, 2024).
117 See PJM. "PJM Manual 13: Emergency Operations," § 3.4 Hot Weather Alert, Rev. 94 (Dec. 18, 2024).
118 See PJM. "PJM Manual 13: Emergency Operations,"§ 2.3.1 Advanced Notice Emergency Procedures: Alerts, Rev. 94 (Dec. 18, 2024).
119 See PJM. "PJM Manual 13: Emergency Operations," § 2.3.2 Real-Time Emergency Procedures (Warnings and Actions), Rev. 94 (Dec. 18, 2024).

Not all emergency procedures defined in Table 3-79 are included in Table 3-80, Table 3-81, Figure 3-51, Figure 3-52, Figure 3-54 and Figure 3-55, even if they occurred in the first nine months of 2025. Synchronized reserve events are covered in more detail in Section 10. Information about frequent events is treated separately. Post Contingency Local Load Relief Warnings (PCLLRWs) and Non-Market Post Contingency Local Load Relief Warnings (NMPCLLRWs) are shown in Figure 3-56 and Figure 3-57. Transmission loading relief informational postings (TLRs) are discussed in other sections of this report. Local load relief warnings provide to transmission owners advanced warning of possible local load shed in an area in order to relieve a local constraint and are separate from manual load dump warnings. Transmission loading relief is a NERC procedure for curtailing interchange transactions to avoid violating operational limits of the system.[120] [121]

Table 3-80 shows the dates affected by emergency alerts, warnings, actions, and informational postings in the first nine months of 2025. Events in Table 3-80 can span multiple days, but only the first day is shown. Advisories, alerts, warnings, and informational postings do not necessarily take effect immediately. For example, for cold weather alerts, the dates affected are when PJM expects the cold weather requiring the alert to occur. For maintenance outage recalls, the dates affected are from the date PJM initiates the recall until the date the units are expected to be available. Figure 3-51 shows the timeline of the advisories, alerts, warnings, actions, and the maintenance outage recall during the January 2025 polar vortex. Figure 3-52 shows the timeline of the alerts, actions, and the maintenance outage recall during the June 2025 hot weather event. Figure 3-53 shows the timeline of the alerts, actions, and the maintenance outage recall during the July 2025 heatwave.

120 NERC IRO-006-5. "Reliability Coordination — Transmission Loading Relief (TLR)," November 4, 2010. <https://www.nerc.com/pa/Stand/Reliability%20Standards/IRO-006-5.pdf>.
121 NERC IRO-006-EAST-2. "Transmission Loading Relief Procedure for the Eastern Interconnection," August 13, 2015. <https://www.nerc.com/pa/Stand/Reliability%20Standards/IRO-006-EAST-2.pdf>.

Table 3-80 Starting days of declared emergency alerts, warnings actions, and certain informational postings: January through September, 2025

Date	Cold Weather Alert	Hot Weather Alert	Conservative Operations	Emergency Energy Request	Pre-Emergency Mandatory Load Management Reduction	Emergency Mandatory Load Management Reduction	Geomagnetic Disturbance Warning	Geomagnetic Disturbance Action	Low Voltage Alert	High System Voltage Action	Load Shed Directive	Unit Startup Notification Alert	Maintenance Outage Recall	Maximum Emergency Generation Alert	Maximum Emergency Generation Action	Voltage Reduction Action
01-Jan-2025							PJM RTO									
08-Jan-2025	Western															
14-Jan-2025	Western															
15-Jan-2025													PJM RTO			
19-Jan-2025									PJM RTO							
20-Jan-2025	PJM RTO		PJM RTO													
22-Jan-2025														PJM RTO		
16-Feb-2025			PJM RTO													
17-Feb-2025	Western		PJM RTO													
19-Feb-2025	Western				DOM_ASHBURN											
30-Mar-2025										PJM RTO						
16-Apr-2025							PJM RTO									
18-Apr-2025										PJM RTO						
19-Apr-2025										PJM RTO						
20-Apr-2025										PJM RTO						
26-Apr-2025										PJM RTO						
27-Apr-2025										PJM RTO						
11-May-2025										PJM RTO						
18-May-2025										Western						
24-May-2025										PJM RTO						
28-May-2025							PJM RTO									
01-Jun-2025							PJM RTO	COMED		PJM RTO						
02-Jun-2025							PJM RTO									
12-Jun-2025							PJM RTO									
18-Jun-2025													PJM RTO			
22-Jun-2025		PJM RTO														
23-Jun-2025					Mid-Atlantic except RECO, SMECo, SRE, UGI; Southern									PJM RTO		
24-Jun-2025					Mid-Atlantic except RECO, SMECo, SRE, UGI; Southern; Western except AMPT, CPP, ITCI, OVEC, WVPAT									PJM RTO		
25-Jun-2025					Mid-Atlantic except RECO, SMECo, SRE, UGI; Southern; FE-AP									PJM RTO		
26-Jun-2025		PJM RTO														
06-Jul-2025		Western except COMED, ITCI														
07-Jul-2025		Mid-Atlantic, Southern														
15-Jul-2025														PJM RTO		
16-Jul-2025														PJM RTO		
17-Jul-2025		Mid-Atlantic, Southern														
18-Jul-2025													PJM RTO			
23-Jul-2025		Western														
24-Jul-2025		PJM RTO												PJM RTO		
25-Jul-2025		PJM RTO												PJM RTO		
26-Jul-2025		Mid-Atlantic, Southern														
28-Jul-2025		PJM RTO			Southern, BGE, PEPCO									PJM RTO		
29-Jul-2025		PJM RTO			Mid-Atlantic except RECO, SMECo, SRE, UGI; Southern; Western except AMPT, CPP, ITCI, OVEC, WVPAT									PJM RTO		
30-Jul-2025		PJM RTO												PJM RTO		
06-Aug-2025													PJM RTO			
11-Aug-2025					BGE	BGE					BGE					BGE
12-Aug-2025		Mid-Atlantic														
17-Aug-2025		PJM RTO														
30-Aug-2025										PJM RTO						
31-Aug-2025										PJM RTO						
01-Sep-2025										PJM RTO						
07-Sep-2025										Western						
08-Sep-2025										Western						
14-Sep-2025							PJM RTO									
30-Sep-2025							PJM RTO									

Figure 3-51 Days with applicable alerts, actions, and recalls[122]: January 14 through January 25, 2025

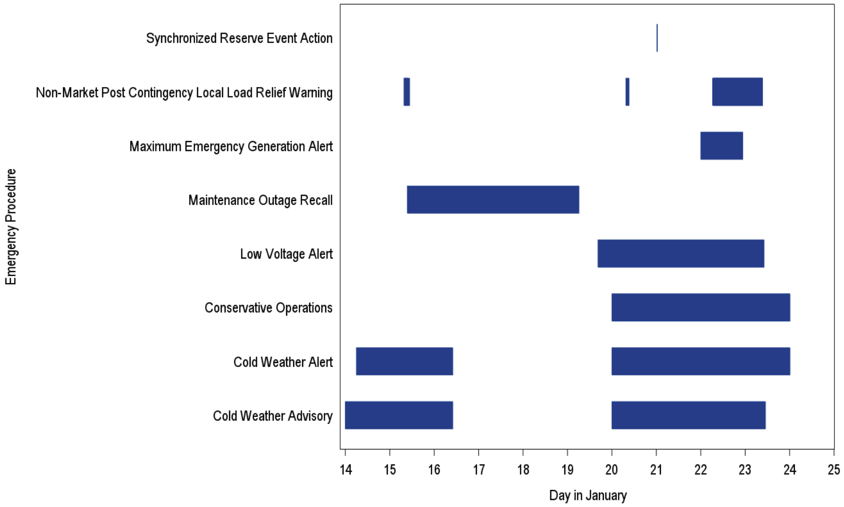
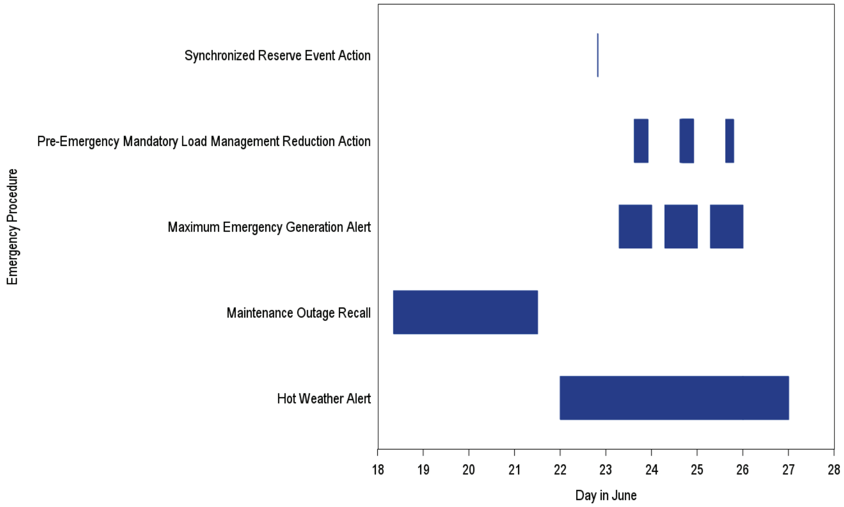


Figure 3-52 Days with applicable alerts, actions, and recalls: June 18 through June 27, 2025



122 To be consistent with other statistics in this section, the length of the maintenance outage recall has been reduced to the days starting from when the recall was issued until the time units were expected to be available. In the previous report, the recall was shown as lasting until near the end of the cold weather.

Figure 3-53 Days with applicable alerts, actions, and recalls[123]: July 14 through July 31, 2025

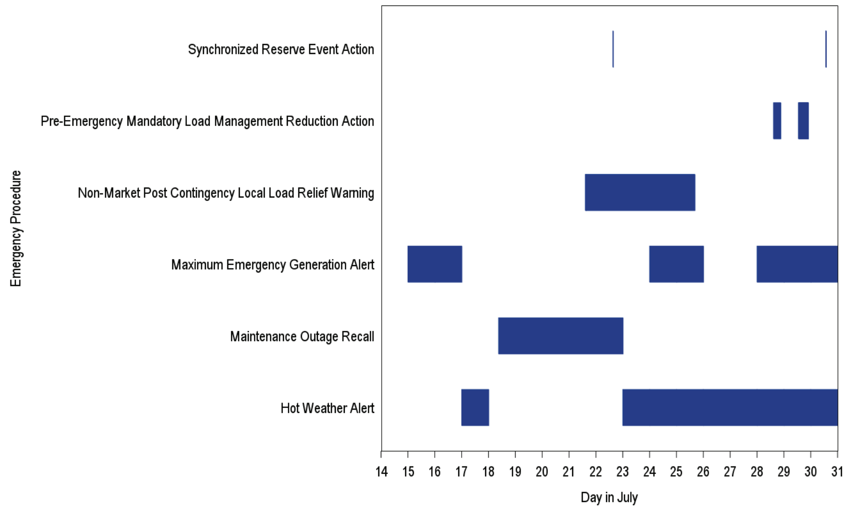


Table 3-81 shows the number of days for which emergency alerts, warnings, actions, and informational postings were declared by PJM in the first nine months of 2024 and the first nine months of 2025. In the first nine months of 2025, there were zero days with emergency actions and shortages that triggered Performance Assessment Intervals (PAI).[124] The voltage reduction action on August 11, 2025, did not trigger a PAI because the action was limited to the BGE region.[125]

Table 3-81 Number of days for which PJM declared events (alerts, warnings, actions, and certain informational postings)[126]: January through September, 2024 and 2025

	Number of days for which events declared	
Event Type	2024 (Jan-Sep)	2025 (Jan-Sep)
Cold Weather Alert	8	13
Conservative Operations	5	8
Emergency Mandatory Load Management Reduction Action	0	1
Geomagnetic Disturbance Action	2	1
Geomagnetic Disturbance Warning	15	13
High System Voltage Action	6	18
Hot Weather Alert	28	18
Load Shed Directive	0	1
Low Voltage Alert	0	5
Maintenance Outage Recall	7	28
Maximum Emergency Generation Alert	1	11
Pre-Emergency Mandatory Load Management Reduction Action	0	7
Voltage Reduction Action	0	1
Shortage Pricing	29	130
Energy export recalls from PJM capacity resources	0	0

123 To be consistent with other statistics in this section, the length of the maintenance outage recall has been reduced to the days starting from when the recall was issued until the time units were expected to be available. In the previous report, the recall was shown as lasting until near the end of the cold weather.
124 A PAI is triggered when PJM takes an emergency action and there is a shortage of primary reserves. See 184 FERC ¶ 61,058 (2023).
125 See "August 11 BGE Load Shed Event," PJM presentation to the Operating Committee. (September 11, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250911/20250911-item-04---bge-load-shed-event.pdf>

126 TLRs, Post Contingency Local Load Relief Warnings, and Non-Market Post Contingency Local Load Relief Warnings are excluded due to their high frequency.

Figure 3-54 shows the number of days for which emergency alerts were issued in PJM in the first nine months of 2021 through 2025.

Figure 3-55 shows the number of days for which emergency warnings and actions were declared in PJM in the first nine months of 2021 through 2025.

Figure 3-54 Number of days for which emergency alerts declared: January through September, 2021 through 2025

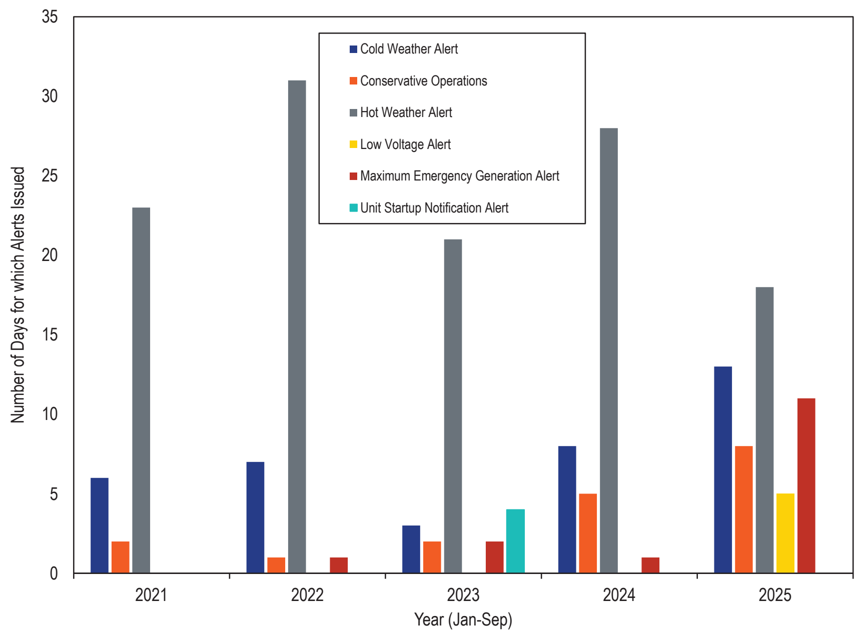


Figure 3-55 Declared emergency warnings and actions: January through September, 2021 through 2025

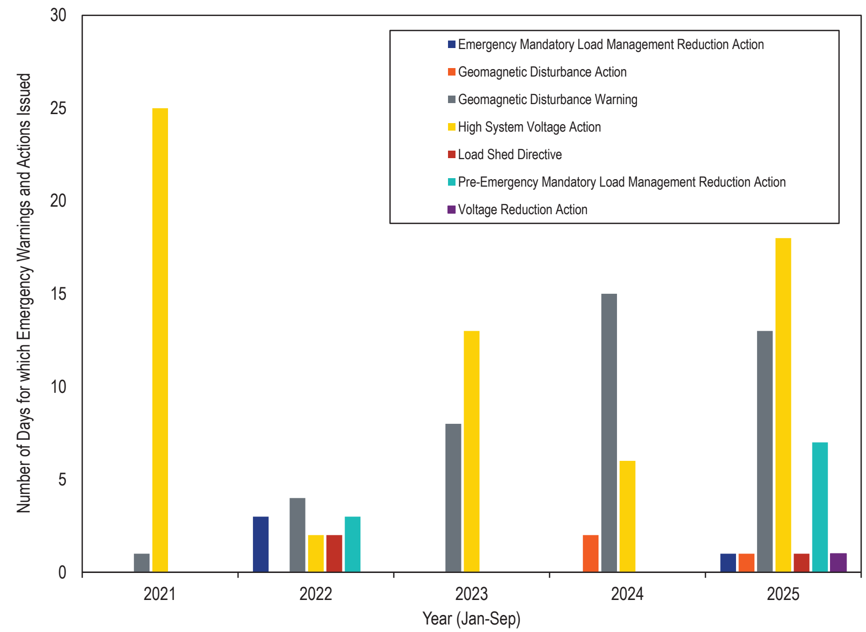


Figure 3-56 shows the number of local load relief warnings declared in PJM in the first nine months of 2025. Figure 3-57 shows the number of post-contingency local load relief warnings (PCLLRWs) affecting each area targeted by PCLLRWs. A single PCLLRW can be declared for multiple regions.

Figure 3-56 Declared local load relief warnings: January through September, 2025

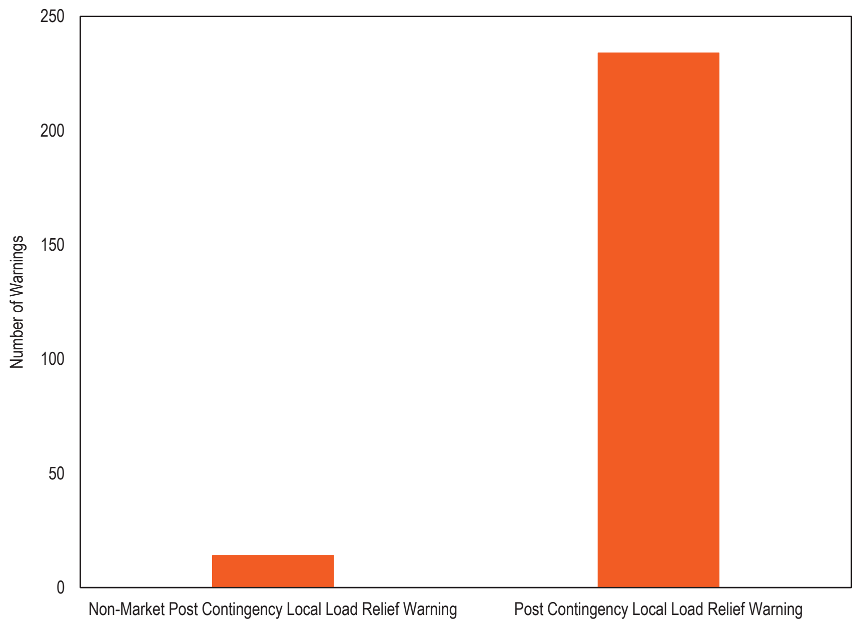
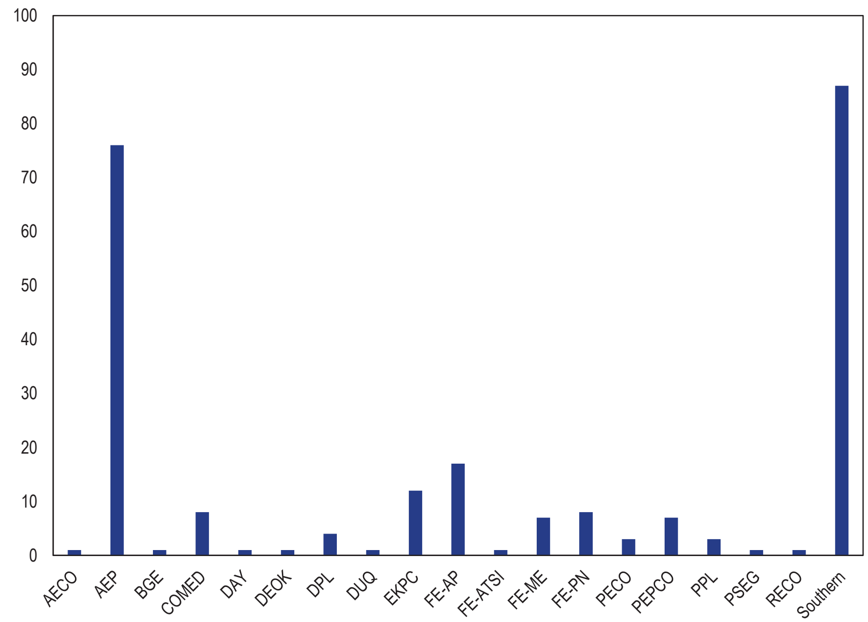


Figure 3-57 Number of post-contingency local load relief warnings affecting an area: January through September, 2025



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 why PJM does not include demand side capacity resources in the definition of reserves. 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.[127] SCED solutions from October 1, 2019, February 16, 2020, and April 21, 2020, indicate that the defined logic met transmission constraint limits and reserve requirements but violated the power balance constraint, and did not reflect this constraint violation in prices. The definitions and implementation of reserves, combined with operator discretion to bias load, make it difficult to define when there is an actual power balance constraint violation. Effective August 8, 2024, PJM updated SCED and LPC to convert reserves to energy before violating the power balance constraint.

During Winter Storm Elliott, on December 23, and December 24, 2022, PJM created what PJM 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 actually exist to the supply (virtual generation). To the extent that there was not an actual violation of the power balance constraint, it was appropriate that PJM did not take actions to address the nonexistent violation.

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 include: the exact definition of the power balance constraint including the role of PJM load bias; a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources to address any actual or potential power balance issue; a process to call on demand side capacity resources, and the minimum level of synchronized reserves that would trigger load shedding. Table 3-82 shows the number of five minute intervals for which the RT SCED solutions did not balance demand and supply. Prior to August 8, 2024, PJM reran the RT SCED with artificially increased supply to satisfy the power balance constraint. In the first nine months of 2025, there were six five-minute intervals that used an RT SCED solution with an apparently violated power balance constraint.

127 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.

On June 24, 2025, PJM apparently violated the power balance constraint for two five minute intervals in the hour beginning at 1800 in the pricing run. In those two five minute intervals, PJM also capped the energy LMP at $3,700 per MWh. However, PJM positively biased the load forecast in the two intervals where the power balance constraint was violated.

Table 3-82 Number of five minute intervals using RT SCED solutions with apparently 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	23	$357.34	$361.14
2024	6	$907.95	$907.95
2025 (Jan - Sep)	6	$3,542.96	$3,123.31

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. That 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 that sets a defined higher price when the system operates with real-time reserves that are lower than the target level.

In the first nine months of 2025, there were 130 five-minute intervals with real-time shortage pricing for one or more reserve products that occurred on 22 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.[128] 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 fully algorithmic or well defined because RT SCED can indicate a shortage that PJM does not use in pricing and because the load bias added to SCED may artificially create or suppress shortages. On June 22, 2020, PJM reduced the frequency of automatic RT SCED executions to every five minutes in order to match the frequency of pricing in the LPC, 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.[129] 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 for 19 intervals in the first nine months of 2025.

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 power balance constraint is met and there is no defined shortage of reserves.[130]

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 reserve 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 additional reserves of at least 190 MW.[131] [132] During reserve shortages, the prices on the demand curve are added to LMP. This is called shortage pricing. Mathematically, when a reserve constraint is not satisfied, the area under the demand curve for the unmet MW of the reserve requirement is added to the market clearing cost-minimization objective function as a penalty for violating a reserve constraint, which causes the administrative price on the ORDC to determine the marginal cost of the reserve shortage. This is why the values on the ORDC are sometimes called penalty factors. Because an additional MW of energy on the margin would require another MW of reserves shortage, the administrative marginal cost of reserves defined by the ORDC is added to LMP.

128 *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).

129 *See* PJM Operating Agreement, Schedule 1, Section 2.5.1(a).

130 *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).

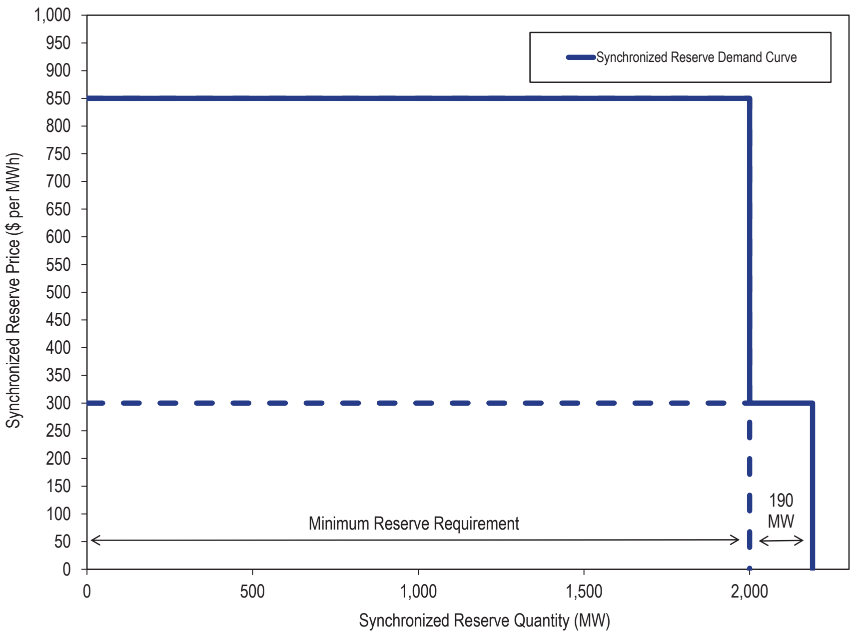
131 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3.3 Reserve Demand Curves and Penalty Factors, Rev. 133 (Dec. 17, 2024).

132 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3 Reserve Requirement Determination, Rev. 133 (Dec. 17, 2024).

Shortage Pricing and Energy Price Formation

The current operating reserve demand curves (ORDC) in PJM define an administrative price for estimated reserves (synchronized, primary, and 30-minute reserves) up to the extended reserve requirement quantities, which for each reserve service is the sum of that service's minimum reserve requirement (MRR) and an extended requirement of at least 190 MW. The price is $850 per MWh for reserve quantities less than the MRR. The price is $300 per MWh for reserve quantities between the MRR and the sum of the MRR and the extended requirement. The example demand curve shown in Figure 3-58 drops to a zero price for quantities above the extended reserve requirement.

Figure 3-58 Example real-time extended synchronized reserve demand curve showing the permanent second step



Historically, the minimum reserve requirement for each operating interval has equaled the size of the largest single source of supply on the PJM system during that operating interval, known as 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. The changes to the reserve requirements are discussed in more detail in Section 10: Ancillary Service Markets.

Nesting

The reserve requirements are nested such that the reserves with shorter allowed response times and stricter synchronization requirements count toward the requirements for reserves with longer allowed response times and less strict synchronization requirements, 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. The market uses constraints to ensure that reliability requirements are met while production costs are minimized. A binding constraint means that the market incurred some additional production cost to satisfy the constraint. A violated constraint has no associated production cost, so the market assigns an administrative cost based on the ORDC. 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 at 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 3-83 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. The RTO to MAD reserve transfer constraint is 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 does not trigger SMP capping, because the marginal unit for energy cannot 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.[133]

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 a $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.

Scenarios G and H are similar to conditions during the highest priced hours of Winter Storm Elliott on December 23 and 24, 2022. In G, the marginal unit offer price is $500 per MWh. The synchronized and primary reserve requirements are violated for the RTO and MAD zones. Transmission constraints affect both the system marginal price and other locations. The SMP in G is capped at $3,700 per MWh. In H, the marginal unit offer price is lower, at $40 per MWh, and the 30 minute reserve constraint is also violated. With the offer caps, the SMP is also at $3,700 per MWh.

The extent to which each transmission penalty factor for a constraint 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 the marginal loss factor and the uncapped system marginal price.

133 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.

Table 3-83 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 in SMP	System Marginal Price		Transmission Constraint Penalty Factor in CLMP	Total LMP	
Scenario	Marginal Unit Offer Price	RTO	MAD	RTO	MAD	RTO		RTO Marginal	MAD Marginal		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
G	$500	$850	$850	$850	$850	$0	$2,000	$3,700	$3,700	$2,000	$5,700	$5,700
H	$40	$850	$850	$850	$850	$850	$2,000	$3,700	$3,700	$2,000	$5,700	$5,700

Shortage Pricing During Synchronized Reserve Events

Synchronized reserves are deployed when PJM declares a synchronized reserve event, also known as a spinning event. PJM's method of communication prior to December 2024 failed to result in reliably timely responses, defined to be within 10 minutes. For units that could receive an electronic signal, PJM's instruction to units supplying reserves was to ignore the dispatch signals sent by RT SCED and to instead ramp their units up until the spin event ends. A significant number of resources did not have the capability to receive the electronic signals that PJM offered. The ALL-CALL system only calls a limited number of contacts at the same time. Although PJM's stated goal was an immediate response, in practice it took minutes for a generator's designated contact to respond to the ALL-CALL, who could then take minutes more to call personnel at the plant. If a unit was following automatic generation control when an event was declared, then additional minutes could also be lost switching to manual control. The end result of these communications issues was that resources started responding only after minutes into an event, even when everything went well.[134] In December 2024, PJM added an automated communication method that would add the reserve deployment instruction to the dispatch signal, which will allow generators following automatic generation control to automatically follow the signal. The new method did not affect any synchronized reserve events in 2024. The new method applied to all 19 events in the first nine months of 2025, of which only four exceeded ten minutes. The new method did not resolve the communications issues for all resources. Significant communications issues remain unresolved.

Although PJM 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 8 to 10 minutes into the future. Currently, RT SCED has the ability to back down units during events to create available reserves, which counteracts PJM's recovery effort. This results in a discrepancy between the RT SCED solutions and the operational need during a spinning event. While PJM recovers from a disturbance during a spinning event, PJM should 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 as intended. 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. For example, nine shortage pricing intervals were artificially triggered during the spin events on February 5, February 11, June 22, August 14, September 4, and September 25, 2025. The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirements by the amount of the reserves deployed.

134 See the *2024 State of the Market Report for PJM*, Volume 2: Section 10: Ancillary Service Markets for a more detailed discussion of these issues.

Reserve Shortages in the First Nine Months of 2025

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 in the RTO Reserve Zone and the MAD Reserve Subzone (synchronized reserve and primary reserve in both areas and 30-minute reserve in the RTO), when multiple solutions indicated shortage of reserves, and how many of these resulted in shortage prices in LPC. 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. To trigger shortage pricing, PJM operators must approve an LPC case in which the MW of reserves in the pricing run of the LPC are short of 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.[135] [136] 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.

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 3-84 shows, in 2024 and the first nine months of 2025, 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 multiple RT SCED solutions 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 3-84 shows that, in 2024, 6,811 target times, or 6.5 percent of all five-minute target times, had at least one RT SCED solution showing a shortage of reserves, and 1,905 target times, or 1.8 percent of all five-minute target times, had more than one RT SCED solution showing a shortage of reserves. In the first nine months of 2025, there were 4,082 target times, or 5.2 percent of all five-minute target times, that had at least one RT SCED solution showing a shortage of reserves, and 1,368 target times, or 1.7 percent of all five-minute target times, that had multiple RT SCED solutions showing a shortage of reserves.

135 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.
136 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 3-84 Real-time monthly five minute SCED target times and pricing intervals with shortage: January 2024 through September 2025

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
2024	Jan	8,928	398	4.5%	119	1.3%	10	2.5%
2024	Feb	8,352	606	7.3%	156	1.9%	0	0.0%
2024	Mar	8,916	876	9.8%	259	2.9%	9	1.0%
2024	Apr	8,640	434	5.0%	103	1.2%	2	0.5%
2024	May	8,928	792	8.9%	249	2.8%	1	0.1%
2024	Jun	8,640	404	4.7%	115	1.3%	2	0.5%
2024	Jul	8,928	390	4.4%	118	1.3%	3	0.8%
2024	Aug	8,928	532	6.0%	119	1.3%	0	0.0%
2024	Sep	8,640	687	8.0%	223	2.6%	2	0.3%
2024	Oct	8,928	654	7.3%	205	2.3%	6	0.9%
2024	Nov	8,652	645	7.5%	157	1.8%	1	0.2%
2024	Dec	8,928	393	4.4%	82	0.9%	3	0.8%
2024	Total	105,408	6,811	6.5%	1,905	1.8%	39	0.6%
2025	Jan	8,928	248	2.8%	75	0.8%	0	0.0%
2025	Feb	8,064	379	4.7%	91	1.1%	3	0.8%
2025	Mar	8,916	653	7.3%	220	2.5%	11	1.7%
2025	Apr	8,640	630	7.3%	224	2.6%	3	0.5%
2025	May	8,928	595	6.7%	195	2.2%	2	0.3%
2025	Jun	8,640	360	4.2%	170	2.0%	79	21.9%
2025	Jul	8,928	384	4.3%	124	1.4%	16	4.2%
2025	Aug	8,928	365	4.1%	109	1.2%	7	1.9%
2025	Sep	8,640	468	5.4%	160	1.9%	9	1.9%
2025	Total	78,612	4,082	5.2%	1,368	1.7%	130	3.2%

As shown in Table 3-84, in 2024, there were 1,905 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 39 unique five-minute intervals with real-time shortage pricing for one or more reserve products. In the first nine months of 2025, there were 1,368 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 130 unique five minute intervals with real-time 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 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 30-Minute Reserves.

In May 2023, PJM increased reserve requirements in response to poor reserve performance by the units selected to provide reserves. PJM unilaterally increased the synchronized reserve reliability requirement by 30 percentage points to 130 percent of the most severe single contingency (MSSC), which consequently increased the primary reserve reliability requirement by 45 percentage points to 195 percent of the MSSC. While the intervals listed in this section were short of their target requirements, many of these intervals still cleared above the average values of the requirements from before the increase.

The average primary reserve requirement from January 2023 through April 2023 was 2,511.4 MW and the average synchronized reserve requirement was 1,741.7 MW. Many of the intervals with shortage pricing were not short in the sense of failing to clear a sufficient amount of reserves for recovering from a contingency event. They were short because of PJM's unilateral increase to the synchronized reserve reliability requirement. Table 3-85 shows the count of intervals with shortage pricing for synchronized reserve (SR), primary reserve (PR), and 30-minute reserve (TMR). As seen in Table 3-85, the majority of intervals with shortage pricing cleared reserves in excess of the original reserve requirements absent PJM's adder.

Table 3-85 Number of shortage pricing intervals which satisfied the unmodified reserve service requirement: January through September, 2025

	Intervals with Shortage Pricing			Intervals where RT SCED Satisfied Original Requirement			Percentage of Intervals where RT SCED Satisfied Original Requirement			Intervals where RT SCED Did Not Satisfy Original Requirement		
Location	SR	PR	TMR	SR	PR	TMR	SR	PR	TMR	SR	PR	TMR
RTO	17	111	22	17	79	16	100.0%	71.2%	72.7%	0	32	6
MAD	6	6	0	4	2	0	66.7%	33.3%	NA	2	4	0

There were 130 unique real-time five minute intervals with shortage pricing for one or more reserve products in the first nine months of 2025, compared to 29 intervals in the first nine months of 2024. In the first nine months of 2025, there were 130 five minute intervals with shortage pricing in the pricing run for one or more reserve products, and there were 111 intervals with shortage in the dispatch run for one or more reserve products. The following tables show intervals with shortage pricing in the pricing run for each reserve service for the RTO Reserve Zone and the MAD Reserve Subzone. 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.

In 2024, there were no hours with shortage pricing in the day-ahead reserve markets. In the first nine months of 2025, there were four unique day-ahead hours with shortage pricing for one or more reserve products. For February 25, in the day-ahead market, there was one hour with shortage pricing for primary reserves in the MAD Reserve Subzone. For July 29, in the day-ahead market, there were three hours with shortage pricing for primary reserves in the RTO Reserve Zone.

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 20 intervals with shortage pricing in the pricing run due to synchronized reserve shortage in the first nine months of 2025. Table 3-86 shows that the 20 intervals were short of synchronized reserves in both the pricing run and the dispatch run. Seven intervals were also short of synchronized reserves in MAD in the pricing and dispatch run. Thirteen intervals were also short of primary reserves in the RTO in the pricing and dispatch runs. Nine intervals were also short of primary reserves in MAD in the pricing and dispatch runs. Seven intervals were also short of 30-minute reserves in the RTO in the pricing and dispatch runs. Six intervals overlapped with spinning events on February 5, February 11, June 22, 2025, and September 4, 2025.

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 Zone during the three intervals with shortage pricing in the pricing run due to synchronized reserve shortage in the first nine months of 2025. Table 3-87 shows that the three intervals were short of synchronized reserves in both the pricing run and the dispatch run. One interval was also short of primary reserves in the RTO in the pricing and dispatch run. Three intervals were also short of 30-minute reserves in the pricing and dispatch run. Five intervals occurred during synchronized reserve events and were also short of synchronized reserve in the RTO in the pricing and dispatch run.

Table 3-88 shows a summary of 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 125 intervals with shortage pricing in the pricing run due to primary reserve shortage in the first nine months of 2025. Of the 125 intervals that were short of primary reserves, 106 were short in both the pricing run and the dispatch run. Eight intervals were also short of primary reserve in the MAD Reserve Subzone in the pricing run and dispatch run. Thirteen intervals were also short of synchronized reserve in the RTO Reserve Zone in the dispatch run and pricing run. Five intervals were also short of synchronized reserve in the MAD Reserve Subzone in the dispatch run and pricing run. Twenty-three intervals were also short of 30-minute reserves in the RTO Reserve Zone in the dispatch run and pricing run. The one interval on February 11, two intervals on June 22, two intervals on August 14, one interval on September 4, and one interval on September 25 overlapped with synchronized reserve events.

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 nine intervals with shortage pricing in the pricing run due to primary reserve shortage in the first nine months of 2025. Table 3-88 shows that all nine intervals were short of primary reserves in both the pricing run and the dispatch run. All nine intervals were also short of primary reserves in the RTO Reserve Zone in the pricing run and the dispatch run. All nine intervals were also short of synchronized reserve in the RTO Reserve Zone in the pricing run and the dispatch run. Four of the intervals were also short of synchronized reserve in the MAD Reserve Subzone in the pricing run and the dispatch run. The intervals on June 22 and September 4 overlapped with synchronized reserve events.

Table 3-90 shows the extended 30-minute reserve requirement, the total 30-minute reserves, the 30-minute reserve shortage, and the 30-minute reserve clearing prices for the RTO Reserve Zone during the 23 intervals with shortage pricing in the pricing run due to primary reserve shortage in the first nine months of 2025. Table 3-88 shows that all 23 intervals were short of 30-minute reserves in both the pricing run and the dispatch run. All 23 intervals were also short of primary reserves in the RTO Reserve Zone in the pricing run and the dispatch run. Three intervals were also short of primary reserve in the MAD Reserve Subzone in the pricing run and the dispatch run. Six intervals were also short of synchronized reserve in the RTO Reserve Zone in the pricing run and the dispatch run. Three of the intervals were also short of synchronized reserve in the MAD Reserve Subzone in the pricing run and the dispatch run. The interval on June 22 occurred during a synchronized reserve event.

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 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.[137] 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.[138] The system marginal penalty of $3,700 per MWh that is actually applied by PJM should be included in the PJM tariff and Operating Agreement.

137 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.
138 OA Schedule 1, Section 3.2.3A(d) and Section 3.2.3A.001(c).

Table 3-86 Real-time RTO synchronized reserve shortage intervals: January through September, 2025

	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)
05-Feb-25 10:05	1,947.0	1,754.6	192.4	$850.00	$850.00	1,947.0	1,754.6	192.4	$850.00	$850.00
05-Feb-25 10:10	1,945.1	1,687.0	258.1	$850.00	$850.00	1,945.1	1,687.0	258.1	$850.00	$850.00
11-Feb-25 09:05	1,952.5	1,854.1	98.5	$600.00	$600.00	1,952.5	1,854.1	98.5	$600.00	$600.00
15-Mar-25 10:25	2,515.1	2,492.9	22.2	$431.13	$431.13	2,515.1	2,492.9	22.2	$431.13	$431.13
15-Mar-25 10:30	2,515.1	2,492.9	22.2	$319.32	$319.32	2,515.1	2,492.9	22.2	$319.32	$319.32
08-Apr-25 07:00	1,920.3	1,720.9	199.4	$1,700.00	$1,700.00	1,920.3	1,720.9	199.4	$1,700.00	$1,700.00
08-Apr-25 07:05	1,920.3	1,530.8	389.5	$1,700.00	$1,700.00	1,920.3	1,530.8	389.5	$1,700.00	$1,700.00
08-Apr-25 07:10	1,920.3	1,720.2	200.1	$1,700.00	$1,700.00	1,920.3	1,720.2	200.1	$1,700.00	$1,700.00
22-Jun-25 19:35	2,515.1	2,325.1	190.0	$1,356.62	$1,356.62	2,515.1	2,325.1	190.0	$1,356.62	$1,356.62
22-Jun-25 19:40	2,515.1	2,055.1	459.9	$1,700.00	$1,700.00	2,515.1	2,055.1	459.9	$1,700.00	$1,700.00
22-Jun-25 19:45	2,515.1	2,055.1	459.9	$1,700.00	$1,700.00	2,515.1	2,055.1	459.9	$1,700.00	$1,700.00
23-Jun-25 20:15	2,515.1	2,406.7	108.3	$2,000.00	$1,700.00	2,515.1	2,406.7	108.3	$2,000.00	$2,000.00
23-Jun-25 20:20	2,515.1	2,309.9	205.2	$2,550.00	$1,700.00	2,515.1	2,309.9	205.2	$2,550.00	$2,550.00
23-Jun-25 20:25	2,515.1	2,435.2	79.8	$2,000.00	$1,700.00	2,515.1	2,435.2	79.8	$2,000.00	$2,000.00
24-Jun-25 11:55	2,515.1	2,416.1	98.9	$1,150.00	$1,150.00	2,515.1	2,416.1	98.9	$1,150.00	$1,150.00
24-Jun-25 18:50	2,515.1	1,619.0	896.1	$2,550.00	$1,700.00	2,515.1	1,619.0	896.1	$2,550.00	$2,550.00
24-Jun-25 18:55	2,515.1	1,615.0	900.1	$2,550.00	$1,700.00	2,515.1	1,615.0	900.1	$2,550.00	$2,550.00
24-Jun-25 19:00	2,515.1	1,668.2	846.9	$2,550.00	$1,700.00	2,515.1	1,668.2	846.9	$2,550.00	$2,550.00
30-Jun-25 12:45	2,515.1	2,325.1	190.0	$525.80	$525.80	2,515.1	2,325.1	190.0	$525.80	$525.80
04-Sep-25 20:00	2,515.1	1,861.7	653.4	$1,700.00	$1,700.00	2,515.1	1,861.7	653.4	$1,700.00	$1,700.00

Table 3-87 Real-time MAD synchronized reserve shortage intervals: January through September, 2025

	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)
05-Feb-25 10:05	1,877.0	1,754.6	122.4	$1,150.00	$1,150.00	1,877.0	1,754.6	122.4	$1,150.00	$1,150.00
05-Feb-25 10:10	1,877.0	1,687.0	190.0	$1,651.36	$1,651.36	1,877.0	1,687.0	190.0	$1,651.36	$1,651.36
11-Feb-25 09:05	1,911.0	1,854.1	56.9	$900.00	$900.00	1,911.0	1,854.1	56.9	$900.00	$900.00
08-Apr-25 07:05	1,645.0	1,530.8	114.2	$2,850.00	$1,700.00	1,645.0	1,530.8	114.2	$2,850.00	$2,850.00
24-Jun-25 18:50	1,809.0	1,619.0	190.0	$4,155.70	$1,700.00	1,809.0	1,619.0	190.0	$4,155.71	$4,155.71
24-Jun-25 18:55	1,805.0	1,615.0	190.0	$3,700.00	$1,700.00	1,805.0	1,615.0	190.0	$3,700.00	$3,700.00
24-Jun-25 19:00	1,805.0	1,668.2	136.8	$3,700.00	$1,700.00	1,805.0	1,668.2	136.8	$3,700.00	$3,700.00

Table 3-88 Daily summary of real-time RTO primary reserve shortage intervals: January through September, 2025

		Pricing Run					Dispatch Run				
Day (EPT)	Intervals of Shortage	Average RTO Extended Primary Reserve Requirement (MW)	Average Total RTO Primary Reserves (MW)	Average RTO Primary Reserve Shortage (MW)	Average Uncapped RTO Primary Reserve Clearing Price ($/MWh)	Average Capped RTO Primary Reserve Clearing Price ($/MWh)	Average RTO Extended Primary Reserve Requirement (MW)	Average Total RTO Primary Reserves (MW)	Average RTO Primary Reserve Shortage (MW)	Average Uncapped RTO Primary Reserve Clearing Price ($/MWh)	Average Capped RTO Primary Reserve Clearing Price ($/MWh)
11-Feb-25	1	2,833.8	2,821.0	12.832	$300.00	$300.00	2,833.8	2,821.0	12.832	$300.00	$300.00
12-Mar-25	1	3,677.6	3,445.5	232.121	$850.00	$850.00	3,677.6	3,445.5	232.121	$850.00	$850.00
18-Mar-25	4	3,677.6	3,258.0	419.544	$850.00	$850.00	3,677.6	3,258.0	419.544	$850.00	$850.00
19-Mar-25	4	3,677.6	3,494.5	183.111	$575.00	$575.00	3,677.6	3,506.3	171.299	$575.00	$575.00
8-Apr-25	3	2,785.4	1,929.2	856.227	$850.00	$850.00	2,785.4	1,929.2	856.227	$850.00	$850.00
8-May-25	2	3,677.6	3,652.0	25.529	$300.00	$300.00	3,677.6	3,652.0	25.529	$300.00	$300.00
22-Jun-25	5	3,677.6	2,915.8	761.785	$850.00	$850.00	3,677.6	2,915.8	761.785	$850.00	$850.00
23-Jun-25	32	3,677.6	3,242.3	435.259	$989.50	$894.41	3,677.6	3,254.9	422.678	$958.19	$958.19
24-Jun-25	39	3,677.6	3,141.3	536.293	$894.21	$811.13	3,677.6	3,172.6	505.005	$869.31	$869.31
25-Jun-25	2	3,677.6	3,159.0	518.595	$850.00	$850.00	3,677.6	3,159.0	518.595	$850.00	$850.00
8-Jul-25	1	3,677.6	3,643.5	34.045	$300.00	$300.00	3,677.6	3,677.6	0.000	$170.92	$170.92
15-Jul-25	4	3,677.6	3,611.8	65.729	$300.00	$300.00	3,677.6	3,677.6	0.000	$289.55	$289.55
28-Jul-25	11	3,677.6	3,265.8	411.760	$537.29	$537.29	3,677.6	3,280.3	397.327	$497.52	$497.52
14-Aug-25	4	3,677.6	3,440.5	237.081	$551.91	$551.91	3,677.6	3,440.8	236.814	$551.91	$551.91
15-Aug-25	3	3,694.5	3,576.8	117.662	$483.33	$483.33	3,694.5	3,593.9	100.555	$474.25	$474.25
1-Sep-25	1	3,677.6	3,675.0	2.546	$300.00	$300.00	3,677.6	3,675.0	2.546	$300.00	$300.00
4-Sep-25	2	3,677.6	2,994.5	683.122	$850.00	$850.00	3,677.6	2,994.5	683.122	$850.00	$850.00
5-Sep-25	1	3,677.6	3,660.2	17.347	$300.00	$300.00	3,677.6	3,677.6	0.000	$290.05	$290.05
25-Sep-25	5	3,761.0	3,594.7	166.313	$630.00	$630.00	3,761.0	3,619.3	141.625	$624.87	$624.87

Table 3-89 Real-time MAD primary reserve shortage intervals: January through September, 2025

	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)
08-Apr-25 07:00	2,372.5	1,992.9	379.7	$1,700.00	$1,275.00	2,372.5	1,992.9	379.7	$1,700.00	$1,700.00
08-Apr-25 07:05	2,372.5	1,802.7	569.8	$1,700.00	$1,275.00	2,372.5	1,802.7	569.8	$1,700.00	$1,700.00
08-Apr-25 07:10	2,372.5	1,992.2	380.4	$1,700.00	$1,275.00	2,372.5	1,992.2	380.4	$1,700.00	$1,700.00
22-Jun-25 19:40	2,627.5	2,526.7	100.8	$1,150.00	$1,150.00	2,627.5	2,526.7	100.8	$1,150.00	$1,150.00
22-Jun-25 19:45	2,627.5	2,526.7	100.8	$1,150.00	$1,150.00	2,627.5	2,526.7	100.8	$1,150.00	$1,150.00
24-Jun-25 18:50	2,618.5	1,621.4	997.1	$2,550.00	$1,275.00	2,618.5	1,621.4	997.1	$2,550.00	$2,550.00
24-Jun-25 18:55	2,612.5	1,617.4	995.1	$2,550.00	$1,275.00	2,612.5	1,617.4	995.1	$2,550.00	$2,550.00
24-Jun-25 19:00	2,612.5	1,670.6	941.9	$2,550.00	$1,275.00	2,612.5	1,670.6	941.9	$2,550.00	$2,550.00
04-Sep-25 20:00	2,681.5	2,576.4	105.0	$1,150.00	$1,150.00	2,681.5	2,576.4	105.0	$1,150.00	$1,150.00

Table 3-90 Real-time RTO 30-minute reserve shortage intervals: January through September, 2025

	Pricing Run					Dispatch Run				
Interval (EPT)	RTO Extended 30-Minute Reserve Requirement (MW)	Total RTO 30-Minute Reserves (MW)	RTO 30-Minute Reserve Shortage (MW)	Uncapped RTO 30-Minute Reserve Clearing Price ($/MWh)	Capped RTO 30-Minute Reserve Clearing Price ($/MWh)	RTO Extended 30-Minute Reserve Requirement (MW)	Total RTO 30-Minute Reserves (MW)	RTO 30-Minute Reserve Shortage (MW)	Uncapped RTO 30-Minute Reserve Clearing Price ($/MWh)	Capped RTO 30-Minute Reserve Clearing Price ($/MWh)
23-Jun-25 19:35	3,677.6	3,487.6	190.0	$617.80	$617.80	3,677.6	3,487.6	190.0	$617.80	$617.80
23-Jun-25 19:40	3,677.6	3,487.6	190.0	$692.22	$692.22	3,677.6	3,487.6	190.0	$692.22	$692.22
23-Jun-25 19:45	3,677.6	3,459.4	218.1	$850.00	$850.00	3,677.6	3,459.4	218.1	$850.00	$850.00
23-Jun-25 19:50	3,677.6	3,302.6	375.0	$850.00	$850.00	3,677.6	3,302.6	375.0	$850.00	$850.00
23-Jun-25 19:55	3,677.6	3,487.6	190.0	$676.49	$676.49	3,677.6	3,487.6	190.0	$676.49	$676.49
23-Jun-25 20:05	3,677.6	3,487.6	190.0	$380.81	$380.81	3,677.6	3,487.6	190.0	$380.81	$380.81
23-Jun-25 20:10	3,677.6	3,487.6	190.0	$631.19	$631.19	3,677.6	3,487.6	190.0	$631.19	$631.19
23-Jun-25 20:15	3,677.6	3,091.6	586.0	$850.00	$850.00	3,677.6	3,091.6	586.0	$850.00	$850.00
23-Jun-25 20:20	3,677.6	3,060.9	616.7	$850.00	$850.00	3,677.6	3,060.9	616.7	$850.00	$850.00
23-Jun-25 20:25	3,677.6	3,233.6	444.0	$850.00	$850.00	3,677.6	3,233.6	444.0	$850.00	$850.00
23-Jun-25 20:30	3,677.6	3,666.4	11.1	$300.00	$300.00	3,677.6	3,666.4	11.1	$300.00	$300.00
24-Jun-25 18:20	3,677.6	3,487.6	190.0	$375.98	$375.98	3,677.6	3,487.6	190.0	$375.98	$375.98
24-Jun-25 18:25	3,677.6	3,514.9	162.6	$300.00	$300.00	3,677.6	3,514.9	162.6	$300.00	$300.00
24-Jun-25 18:35	3,677.6	3,487.6	190.0	$544.68	$544.68	3,677.6	3,487.6	190.0	$544.68	$544.68
24-Jun-25 18:40	3,677.6	3,211.6	465.9	$850.00	$850.00	3,677.6	3,211.6	465.9	$850.00	$850.00
24-Jun-25 18:45	3,677.6	2,915.8	761.8	$850.00	$850.00	3,677.6	2,915.8	761.8	$850.00	$850.00
24-Jun-25 18:50	3,677.6	2,491.4	1,186.2	$850.00	$850.00	3,677.6	2,491.4	1,186.2	$850.00	$850.00
24-Jun-25 18:55	3,677.6	1,830.6	1,847.0	$850.00	$850.00	3,677.6	1,830.6	1,847.0	$850.00	$850.00
24-Jun-25 19:00	3,677.6	1,903.5	1,774.0	$850.00	$850.00	3,677.6	1,903.5	1,774.0	$850.00	$850.00
24-Jun-25 19:05	3,677.6	3,042.8	634.7	$850.00	$850.00	3,677.6	3,042.8	634.7	$850.00	$850.00
24-Jun-25 19:10	3,677.6	3,487.6	190.0	$650.74	$650.74	3,677.6	3,487.6	190.0	$650.74	$650.74
24-Jun-25 19:15	3,677.6	3,487.6	190.0	$639.86	$639.86	3,677.6	3,487.6	190.0	$639.86	$639.86
24-Jun-25 19:20	3,677.6	3,487.6	190.0	$554.92	$554.92	3,677.6	3,487.6	190.0	$554.92	$554.92

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 has an administrative maximum price of $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 ex post 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 maximum price. The LMP at a pricing node could still exceed $3,700 per MWh. Unlike other administrative caps, such as the cap on the shadow price of a transmission constraint enforced through transmission penalty factor within the optimization, the SMP cap is not enforced within the optimization. When the SMP cap is enforced, the resulting LMPs are not consistent and do not accurately reflect the marginal cost of serving energy and reserves.

Table 3-91 shows the number of five minute intervals in the real-time market where the SMP was capped for each year since 2018. In the first nine months of 2025, there were four five minute intervals in the real-time market in which the SMP was capped.

Table 3-91 Number of five minute intervals with capped SMP: 2018 through September 2025

Year	Number of Five Minute Intervals with capped SMP
2018	0
2019	1
2020	1
2021	2
2022	51
2023	1
2024	0
2025 (Jan - Sep)	4

The MMU recommends that PJM stop capping the system marginal price 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.[139] 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

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

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.

Generators can deselect themselves from providing reserves by communicating to PJM that their resources will not follow the dispatch signal (e.g. offer fixed gen or operate as nondispatchable). These actions allow generators to withhold reserves and result in a violation of the reserve must offer requirement when the resources operate below their economic maximum.

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 for 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 both local and aggregate 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.

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.[140]

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 2025, 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 PJM's flawed market power 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 2025 was unconcentrated on average (Table 3-92).[141] 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.

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

141 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 3-92 Real-time hourly aggregate energy market HHI: January through September, 2024 and 2025

HHI Statistic	Hourly Market HHI (Jan-Sep 2024)	Hourly Market HHI (Jan-Sep 2025)
Average	699	686
Minimum	553	511
Maximum	983	988
Highest market share (One hour)	26%	24%
Average of the highest hourly market share	18%	17%
# Hours	6,575	6,551
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-93 includes HHI values by supply curve segment, including base, intermediate and peaking plants in the first nine months of 2024 and 2025. On average, ownership in the baseload segment was unconcentrated, in the intermediate segment was moderately concentrated, and in the peaking segment was highly concentrated.[142]

Table 3-93 Real-time hourly energy market HHI by generation segment: January through September, 2024 and 2025

	Jan-Sep 2024			Jan-Sep 2025		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	573	727	1015	645	800	1101
Intermediate	438	1586	5992	424	912	2746
Peak	829	6293	10000	839	6616	10000

Figure 3-59 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 2025.[143]

Figure 3-59 Real-time ICAP distribution by fuel and segment: January through September, 2025[144]

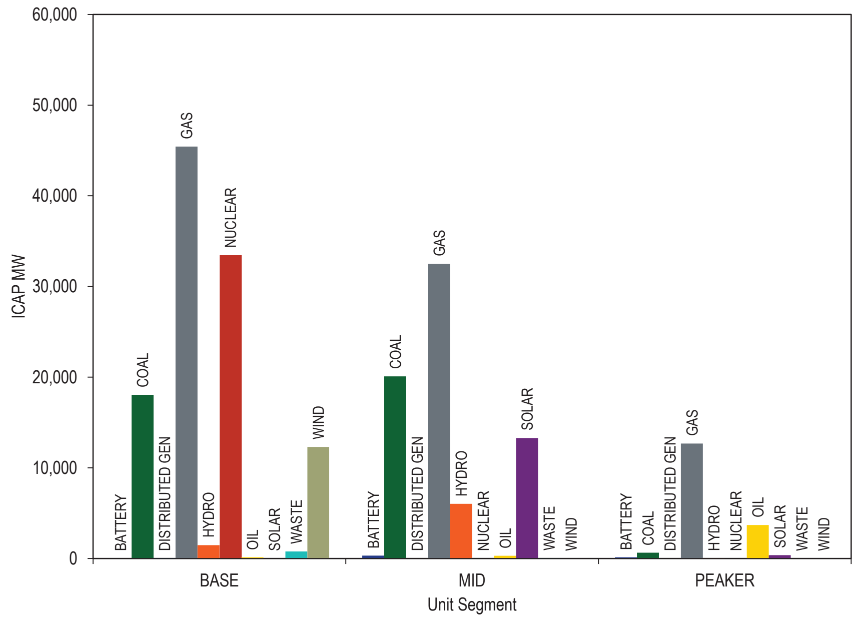


Figure 3-60 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking from the first nine months of 2014 through 2025. Figure 3-60 shows that the total ICAP of coal fired units in PJM classified as baseload generally decreased from the first nine months of 2014 through 2025, 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.

142 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.
143 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.
144 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).

Figure 3-60 Real-time annual gas and coal unit segment classification: January through September, 2014 through 2025

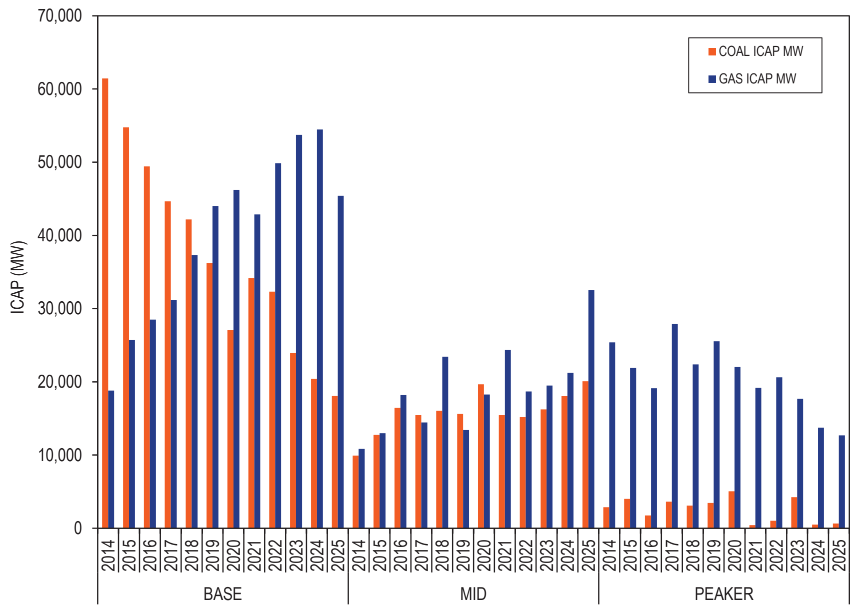


Figure 3-61 Real-time hourly aggregate energy market HHI: January through September, 2025

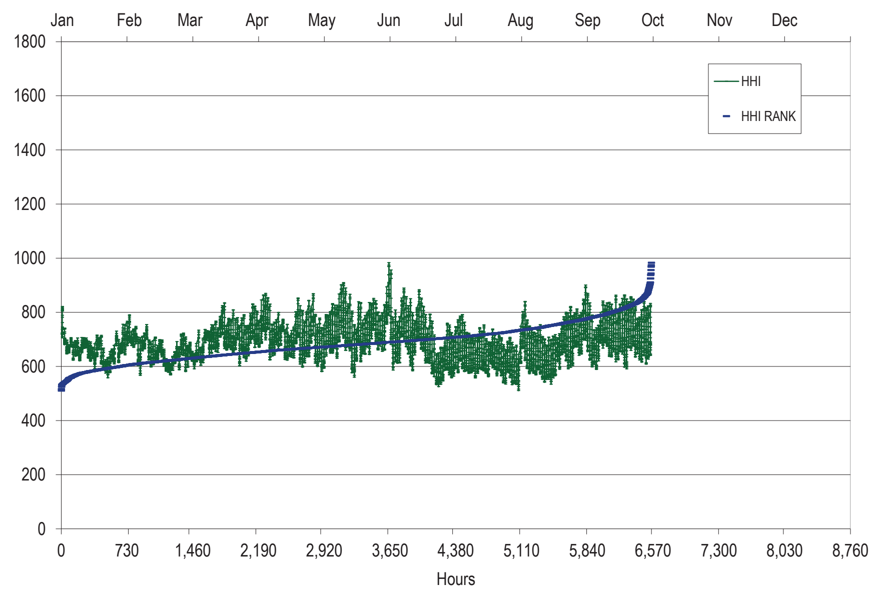


Figure 3-61 presents the hourly HHI values in chronological order and an HHI duration curve for the first nine months of 2025.

Market Based Rates

Participation by generators in the PJM market using offers that exceed costs requires market based rate authority approved by FERC.[145] FERC reviews the market based rate authority of PJM market sellers of generation 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

145 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).

that market monitoring and market power mitigation are sufficient to ensure competitive market outcomes.[146]

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, December 2022, and June 2023 triennial review filings by generating unit owners in PJM. The MMU explained the issues with PJM's offer schedule selection process that allow generators to avoid energy market power mitigation as well as the then overstated capacity market seller offer cap. 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.[147] 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.[148] [149] FERC addressed the capacity market Market Seller Offer Cap later in 2021.[150] [151] FERC did not address the energy market power mitigation issues.

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."[152] [153]

FERC applies tests set forth in the 1996 Merger Policy Statement, written prior to the introduction of competitive markets in PJM.[154] [155] 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.[156] 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 the results of a Competitive Analysis Screen measuring HHI changes for markets defined by transmission zones. This approach does not take into account the effect of a transaction on actual PJM LMPs or capacity market prices.

The MMU reviews proposed mergers and acquisitions based on analysis of the impact of the merger or acquisition on market power given actual PJM market

146 *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").
147 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); Comments of the Independent Market Monitor for PJM, Docket No. ER23-9-000 et al. (August 28, 2023).
148 See 175 FERC ¶ 61,231 (2021).
149 See 174 FERC ¶ 61,212 (2021).
150 See 176 FERC ¶ 61,137 (2021), *reh'g denied*, 178 FERC ¶ 61,121 (2022), *appeal denied*, Vistra Corp. v. FERC, 80 F.4th 302 (2023).
151 *See* Monitoring Analytics, L.L.C., *2021 Annual State of the Market Report for PJM*, Vol. 2, Section 5: Capacity Market at 311-312.
152 18 U.S.C. § 824b.
153 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)
154 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).
155 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.
156 See 138 FERC ¶ 61,109 (2012).

conditions under the current competitive market design. 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 with FERC including such analyses.[157] The MMU has proposed that FERC adopt this approach when evaluating mergers in PJM.[158] Subsequent to the MMU's arguments about local markets, FERC has required further analysis of local markets from applicants at the transmission zone level.[159] FERC has considered the MMU's analysis in reviewing mergers but continues to apply an analysis that does not accurately account for locational market power in an LMP market.[160]

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. For this reason, the MMU recommends that FERC approve mergers and acquisitions conditioned on behavioral commitments by the market sellers that prevent the exercise of market power.

The MMU has also reached agreements to mitigate market power in cases where market power concerns have been identified.[161] [162] 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.

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 3-94 shows ownership changes in the PJM market that involved entire resources that were completed in the first nine months of 2025, as reported to the Commission. Table 3-95 shows transactions that involved transfers of partial unit ownership that were completed in the first nine months of 2025, as reported to the Commission.[163]

157 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).

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

159 See, for example, Darby Power, LLC, et al., Response to Second Deficiency Letter, Request for Confidential Treatment, Request for Shortened Comment Period, and Request for Expeditious Action, Docket No. EC24-125 (March 27, 2025).

160 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).

161 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.

162 See 192 FERC ¶ 61,074 at 169. FERC accepted Constellation's behavioral commitments agreed to with the MMU and conditioned its approval of the acquisition of Calpine on those commitments.

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

Table 3-94 Completed transfers of entire resources: January through September, 2025

Generator or Generation Owner Name	From	To	Transaction Completion Date	Docket
Albemarle Beach Solar, LLC	SE1 Holdings, LLC	True Green Capital Management, LLC	March 12, 2025	EC24-89
St. Joseph Energy Center, LLC	Ares Management Corporation	Wabash Valley Power Association, Inc. (50%) and Hoosier Energy Rural Electric Cooperative, Inc. (50%)	March 13, 2025	EC24-108
Altus Power, Inc.	Altus Power, Inc.	TPG, Inc.	April 16, 2025	EC25-57
Hill Top Energy Center LLC	Ares Management Corporation	Ardian US, LLC	April 23, 2025	EC25-34
Harts Mill Solar, LLC	Irradiant Partners, LP	Apollo Global Management, Inc	May 30, 2025	EC25-63
Dodson Creek Solar, LLC; Fayette Solar, LLC; Ross County Solar, LLC; Sycamore Creek Solar, LLC; Yellowbud Solar, LLC	National Grid, plc	Brookfield Corporation	May 29, 2025	EC25-64
Hummel Station, LLC and Rolling Hills Generating, L.L.C.	LS Power Development, LLC	Capital Power Corporation	June 9, 2025	EC25-79
Hillcrest Solar I, LLC	Innergex Renewable Energy Inc.	Caisse de dépôt et placement du Québec	July 21, 2025	EC25-69
Lightstone Marketing LLC (Darby Power, LLC; Gaving Power, LLC; Lawrenceburg Power, LLC; and Waterford Power, LLC)	Arclight Capital (50%) and Blackstone Inc. (50%)	Bridgepoint Group PLC	July 23, 2025	EC24-125
Potomac Energy Center	Ares Management Corporation	Blackstone Inc.	August 5, 2025	EC25-46
Camden Plant Holdings, LLC	Talen Energy Corporation	Partners Group AG	September 11, 2025	EC25-96
Red Oak Power, LLC	Morgan Stanley	Strategic Value Partners, LLC	September 12, 2025	EC25-115

Table 3-95 Completed transfers of partial ownership of resources: January through September, 2025

Generator or Generation Owner Name	Percent	From	To	Transaction Completion Date	Docket
Reworld Holding Corporation (Reworld Camden County, Reworld Delaware Valley, Reworld Essex, Reworld Plymouth, Reworld Union)	25.0%	EQT AB	GIC (Ventures) Pte. Ltd.	January 22, 2025	EC25-15
Heritage Public Utilities (Blossburg Power, Brunot Island Power, Gilbert Power, Hamilton Power, Hunterstown Power, Mountain Power, New Castle Power, Niles Power, Ortanna Power, Portland Power, Sayrebille Power, Shawnee Power, Shawville Power, Titus Power, Tolna Power, Warren Generation)	20.0%	J. Aron & Company LLC	Barclays Capital Inc.	January 14, 2025	EC25-23
Heritage Public Utilities (Blossburg Power, Brunot Island Power, Gilbert Power, Hamilton Power, Hunterstown Power, Mountain Power, New Castle Power, Niles Power, Ortanna Power, Portland Power, Sayrebille Power, Shawnee Power, Shawville Power, Titus Power, Tolna Power, Warren Generation)	<20%	Barclays Capital Inc.	XYQ Energy LP (<10%) and PGIM, INC (<10%)	February 20, 2025	EC25-25
Northwest Ohio Wind, LLC	50.0%	Grand River Wind, LLC	Arclight Capital	March 3, 2025	EC25-30
West Deptford Energy, LLC	57.7%	MC West Deptford Energy Investments, LLC (17.5%), ASRC Capital, LLC (11.58%), KPIC USA, LLC (17.5%), The Prudential Insurance Company of America (8.87%), The Lincoln National Life Insurance Company (2.22%)	LS Power Group	March 7, 2025	EC25-35
Birdsboro Power LLC	33.3%	Ares Management Corporation	Strategic Value Partners, LLC	May 1, 2025	EC25-56
Silicon Ranch Corporation (SR Turkey Creek, LLC)	10.2%	Shell plc, TD Bank, and Manulife Financial Corporation	AIP Management P/S	June 6, 2025	EC25-75
GenOn Holdings, Inc (Chalk Point Steam, LLC; Morgantown Power, LLC; Shawville Lessor Genco LLC)	16.0%	GenOn Holdings, Inc	Bank of America Corporation	July 2, 2025	EC25-65
West Deptfod Energy, LLC	14.5%	Ullico Inc.	LS Power Group	October 1, 2025	EC25-126

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 market power in the aggregate energy market. If reliably meeting the PJM system load requires energy from a small number of suppliers, those suppliers are jointly pivotal and have oligopoly market power in the aggregate energy market. 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.[164] FERC's definition of highly concentrated markets, based on an HHI greater than 1800, includes between five and six owners with equal market shares.

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 generally 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.[165] Aggregate market power should be mitigated in the PJM Day-Ahead and Real-Time Markets when the three pivotal supplier test for the aggregate market is failed.

164 Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 104–117.

165 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.

Day-Ahead Aggregate Energy Market Pivotal Suppliers

To assess the number of pivotal suppliers in the aggregate 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.[166] Demand is the total MW required by PJM to meet physical load, cleared load bids, export transactions, and DECs, which is the total cleared supply for the peak hour of the day. A supplier is pivotal if PJM would require some portion of the supplier's available economic capacity in the peak hour of the operating day in order to meet demand. Suppliers are jointly pivotal if PJM would require some portion of the joint suppliers' available economic capacity in the peak hour of the operating day in order to meet demand.

Figure 3-62 shows the number of days in the first nine months of 2025 with one pivotal supplier, two jointly pivotal suppliers, and three jointly pivotal suppliers in the day-ahead aggregate energy market by daily peak load level. It shows that market power, measured by the average number of suppliers that are pivotal, increases with daily peak load. The average number of suppliers that were one of three pivotal suppliers (yellow line) was 65.1 on the 26 days with a peak load less than 90 GW (gray bar) and was 135.9 suppliers on the 30 days with a peak load between 120 and 130 GW. The number of pivotal suppliers generally increases with load. There were eight days with load greater than 150 GW. On two of those days, four suppliers were singly pivotal. On three of those days, five suppliers were singly pivotal. All suppliers that failed the three pivotal supplier screen failed the two pivotal supplier screen on all eight of those days.

166 Generation, imports, demand response, and virtual transactions are assigned to parent companies based on the ultimate parent company owner of their PJM account.

Figure 3-62 Average number of pivotal suppliers in the day-ahead energy market by load level: January through September, 2025

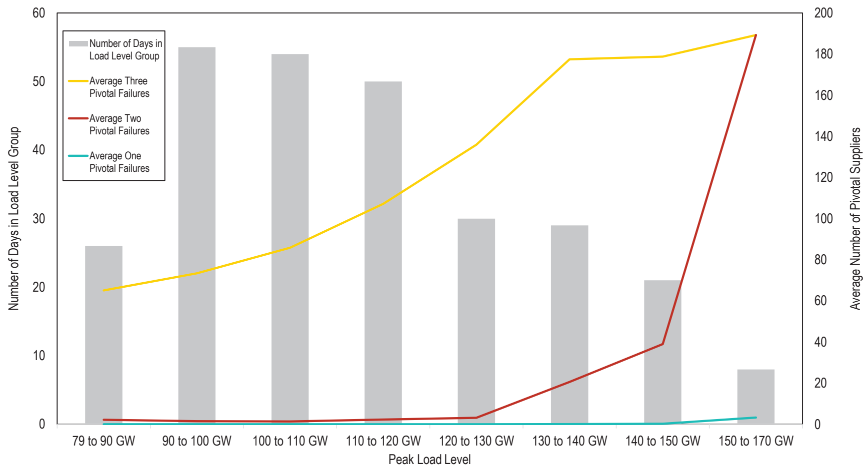


Table 3-96 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the day-ahead aggregate energy market in the first nine months of 2025. All of the top 10 suppliers were one of three pivotal suppliers on at least 168 days in the first nine months of 2025 (61.5 percent of the days). One supplier was singly pivotal on 13 days.

Table 3-96 Day-ahead market pivotal supplier frequency: January through September, 2025

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	13	4.8%	145	53.1%	254	93.0%
2	6	2.2%	161	59.0%	257	94.1%
3	6	2.2%	131	48.0%	257	94.1%
4	5	1.8%	104	38.1%	251	91.9%
5	3	1.1%	86	31.5%	246	90.1%
6	0	0.0%	63	23.1%	223	81.7%
7	0	0.0%	36	13.2%	206	75.5%
8	0	0.0%	34	12.5%	173	63.4%
9	0	0.0%	31	11.4%	194	71.1%
10	0	0.0%	27	9.9%	168	61.5%

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.[167] 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.[168] 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 offers, 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.

167 OA Schedule 1, Section 6.4.1.
168 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>.

TPS Test Statistics for Local Market Power

The TPS test in the energy market defines whether 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 test 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 2025, in the day-ahead energy market, the 500 kV system, 19 of 21 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).[169] Table 3-97 shows that the 500 kV system, 13 of 20 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 the first nine months in every year from 2016 through 2025. DUKE and one zone did not experience congestion resulting from one or more constraints binding for 75 or more hours or resulting from any binding interface constraint in the first nine months in any year from 2016 through 2025.

Table 3-97 Day-ahead congestion hours resulting from one or more constraints binding for 75 or more hours: January through September, 2016 through 2025

	(Jan - Sep)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
500 kV System	4,822	6,301	3,681	4,544	4,741	1,896	2,014	971	1,361	1,341
ACEC	5,037	1,686	2,530	4,631	1,955	824	144	1,057	795	608
AEP	44,324	42,657	13,586	13,085	8,960	4,240	3,309	6,372	5,516	3,468
APS	9,508	9,206	2,382	2,153	3,204	2,442	1,223	1,508	1,855	1,680
ATSI	3,616	3,848	3,186	1,574	184	0	79	497	1,415	680
BGE	11,245	7,433	4,561	3,521	4,716	3,159	993	4,000	1,532	1,810
COMED	36,185	46,042	10,796	3,932	2,949	1,515	2,124	3,186	6,525	4,025
DAY	671	345	300	76	919	220	0	208	0	0
DEOK	7,658	5,820	2,393	1,124	218	517	485	583	324	281
DLCO	200	106	198	0	0	0	97	0	0	79
DOM	4,196	4,755	2,353	727	2,214	1,962	3,646	2,705	3,421	4,806
DPL	12,960	8,691	8,974	6,702	5,006	3,371	2,302	3,591	4,070	2,478
DUKE	0	0	0	0	0	0	0	0	0	0
DUQ	0	0	0	0	0	0	0	0	0	0
EKPC	3,145	1,020	440	0	80	0	0	163	0	218
EXT	0	440	0	0	0	0	0	0	0	0
JCPLC	3,476	2,042	1,030	286	1,648	0	280	1,722	1,381	138
MEC	4,411	4,522	3,425	2,378	1,974	1,359	1,986	1,673	2,902	3,035
NYISO	0	515	0	0	0	0	0	0	0	0
OVEC	0	0	0	1,170	2,410	80	517	1,537	547	649
PE	8,606	17,758	7,485	2,739	3,256	681	3,216	3,829	6,373	7,957
PECO	5,115	8,840	2,643	1,218	917	1,333	3,349	4,404	3,408	2,635
PEPCO	276	643	116	79	0	0	228	364	354	640
PJM/MISO	17,250	18,558	14,699	7,450	4,514	4,334	7,949	4,742	3,782	6,941
PPL	2,175	6,095	3,193	7,328	4,142	3,942	4,707	2,252	2,755	3,017
PSEG	11,784	15,199	5,907	2,589	1,271	2,471	3,896	2,078	1,250	2,292
REC	0	0	326	1,074	182	1,069	723	895	287	0
TVA	223	0	0	206	75	0	0	0	0	0

In the first nine months of 2025, in the real-time energy market, the 500 kV system, 13 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 3-98).[170] Table 3-98 shows that the 500 kV system, six zones, and PJM/MISO experienced congestion resulting from one or more

169 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.

170 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.

constraints binding for 75 or more hours or resulting from a binding interface constraint in every year from 2016 through 2025. Three zones (DUQ, OVEC and REC), and DUKE did not experience congestion resulting from one or more constraints binding for 75 or more hours or resulting from any binding interface constraint in the first nine months in any year from 2016 through 2025.[171]

Table 3-98 Real-time congestion hours resulting from one or more constraints binding for 75 or more hours: January through September, 2016 through 2025

	(Jan - Sep)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
500 kV System	515	810	1,009	2,777	2,075	748	869	375	579	460
ACEC	413	0	94	97	0	0	0	0	0	0
AEP	441	469	1,170	381	887	976	311	534	1,130	878
APS	157	136	184	0	319	888	82	0	181	345
ATSI	0	133	814	0	0	0	78	78	1,015	87
BGE	4,227	1,297	2,144	533	2,040	1,374	495	1,993	804	856
COMED	2,588	913	522	78	856	762	865	600	2,787	2,093
DAY	0	0	0	0	0	181	0	0	0	0
DEOK	0	0	75	0	0	176	0	0	0	132
DOM	553	80	136	91	780	488	1,455	416	664	1,306
DPL	1,991	326	398	0	0	144	0	84	0	158
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	184	0	0	0	0	0	0	0
EXT	0	778	0	0	0	0	0	0	0	0
JCPLC	0	94	0	0	0	0	0	0	0	0
MEC	0	0	553	278	730	302	771	190	587	656
NYISO	730	332	0	0	0	0	0	0	0	0
OVEC	0	0	0	0	0	0	0	0	0	0
PE	141	1,541	1,114	1,013	1,950	586	1,522	2,144	3,818	4,505
PECO	657	1,312	537	224	284	612	2,134	2,552	1,468	1,417
PEPCO	0	0	0	0	0	0	0	0	77	83
PJM/MISO	2,983	3,797	3,060	3,035	2,453	2,458	6,015	3,431	3,494	3,850
PPL	242	563	0	748	460	751	1,582	91	96	477
PSEG	170	160	211	164	0	759	330	0	0	0
REC	0	0	0	0	0	0	0	0	0	0

171 In this report, the MMU used the dispatch run marginal resource and sensitivity factor data, rather than the pricing run data, in the analysis of constraints since 2021 because the PJM pricing run sensitivity factor data for day-ahead LMP was not correct for a small number of hours. The PJM pricing run LMPs are the final settlement LMPs.

In the PJM Day-Ahead Energy Market, the TPS test is performed in PROBE, as part of the unit commitment process. 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 and the average number of owners passing and failing the TPS test for the interface constraints in the PJM Day-Ahead Energy Market.

Table 3-99 Day-ahead three pivotal supplier test details for internal interface constraints: January through September, 2025

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AEP - DOM	Peak	29	501	378	24	3	20
	Off Peak	60	458	1,156	37	24	13
AP South	Peak	117	579	1,072	33	19	14
	Off Peak	27	355	958	30	17	13
BCPEP	Peak	21	524	485	18	2	16
	Off Peak	0	0	0	0	0	0
Bedington - Black Oak	Peak	33	158	216	29	13	15
	Off Peak	21	174	335	33	26	7
Central	Peak	13	1,233	1,236	31	2	29
	Off Peak	0	0	0	0	0	0
West	Peak	19	758	1,189	32	11	21
	Off Peak	0	0	0	0	0	0

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, 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.[172] 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.

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 3-100 Day-ahead three pivotal supplier test details for top 10 congested constraints: January through September, 2025

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Lenox - North Meshoppen	Peak	1,017	79	46	8	1	6
	Off Peak	1,347	67	37	8	1	7
Nottingham	Peak	918	239	331	29	14	15
	Off Peak	667	174	362	27	18	9
Dune Acres - Michigan City	Peak	234	90	54	13	1	12
	Off Peak	691	109	111	18	2	16
Bergen - Hudson	Peak	3	14	33	1	0	1
	Off Peak	2	13	33	1	0	1
Graceton - Manor	Peak	270	303	279	30	8	22
	Off Peak	333	209	274	26	9	17
Haumesser Road - Steward	Peak	472	211	195	10	1	9
	Off Peak	397	177	162	9	1	8
Kewanee	Peak	397	88	74	5	0	5
	Off Peak	338	79	77	5	1	4
Pleasant View - Ashburn	Peak	170	193	149	25	7	18
	Off Peak	52	104	147	23	10	12
Easton - Emuni	Peak	88	360	18	2	0	2
	Off Peak	147	297	29	3	0	3
Carlisle Pike - Gardners	Peak	383	260	26	5	0	5
	Off Peak	180	119	14	4	0	4

172 *See* PJM. "Manual 11: Energy & Ancillary Services Market Operations," Section 5.2.6, Rev. 136 (Oct. 1, 2025).

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 for the first nine months of 2025.[173] 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.[174] 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 did result in offer capping.

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 interface constraints in the PJM Real-Time Energy Market. Table 3-102 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 3-101 and Table 3-102 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

173 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>.

174 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.

ahead times. The set of binding constraints for a target time may be different in 12 look ahead IT SCED solutions.

Table 3-101 Real-time three pivotal supplier test details for internal interface constraints: January through September, 2025

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AEP - DOM	Peak	2,668	600	564	12	0	12
	Off Peak	3,299	588	644	13	0	13
AP South	Peak	2,284	415	437	13	2	11
	Off Peak	966	395	372	10	1	9
Bedington - Black Oak	Peak	1,073	194	195	14	4	10
	Off Peak	687	188	178	13	4	9

Table 3-102 Real-time three pivotal supplier test details for top 10 congested constraints: January through September, 2025

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Lenox - North Meshoppen	Peak	60,729	25	26	2	0	2
	Off Peak	82,640	22	25	2	0	2
Nottingham	Peak	25,254	135	129	11	2	9
	Off Peak	22,985	119	133	11	2	8
Dune Acres - Michigan City	Peak	8,204	34	35	4	0	3
	Off Peak	15,363	31	36	4	0	4
Kewanee	Peak	6,727	20	125	1	0	1
	Off Peak	6,851	18	94	1	0	1
Graceton - Manor	Peak	9,505	137	154	13	3	10
	Off Peak	13,554	116	139	12	2	10
Jordan - West Frankfort	Peak	3,162	46	19	3	0	3
	Off Peak	5,751	52	24	3	0	3
Prest - Tibb	Peak	1,579	31	14	3	0	3
	Off Peak	3,594	25	13	3	0	3
Dresden	Peak	9,740	30	33	2	0	2
	Off Peak	5,391	22	44	2	0	2
Haumesser Road - Steward	Peak	6,813	35	111	2	0	2
	Off Peak	7,010	35	110	2	0	2
Chapparal - Carson	Peak	7,377	55	114	2	0	2
	Off Peak	3,330	57	109	3	0	3

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.[175] 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, and 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 3-103 shows that, in the first nine months of 2025, 4.6 percent of unit hours that cleared the day-ahead market on their price based offer were switched to cost in real-time. Table 3-103 shows that 7.8 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.

175 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 3-103 Day-ahead units committed on price-based offers that cleared real-time: January through September, 2024 and 2025

	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
2024	89,947	2,294,967	199,788	3.9%	8.7%
2025	106,325	2,431,227	191,273	4.6%	7.8%

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 3-104 and Table 3-105 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 3-104 Summary of real-time three pivotal supplier tests applied for internal interface constraints: January through September, 2025

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
AEP - DOM	Peak	2,668	2,661	100%	69	3%	3%
	Off Peak	3,299	3,293	100%	185	6%	6%
AP South	Peak	2,284	2,282	100%	67	3%	3%
	Off Peak	966	960	99%	18	2%	2%
Bedington - Black Oak	Peak	1,073	1,061	99%	17	2%	2%
	Off Peak	687	687	100%	23	3%	3%

Table 3-105 Summary of real-time three pivotal supplier tests applied for top 10 congested constraints: January through September, 2025

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
Lenox - North Meshoppen	Peak	60,729	20,348	34%	2	0%	0%
	Off Peak	82,640	14,275	17%	7	0%	0%
Nottingham	Peak	25,254	24,780	98%	307	1%	1%
	Off Peak	22,985	22,757	99%	253	1%	1%
Dune Acres - Michigan City	Peak	8,204	657	8%	0	0%	0%
	Off Peak	15,363	2,330	15%	0	0%	0%
Kewanee	Peak	6,727	7	0%	0	0%	0%
	Off Peak	6,851	6	0%	0	0%	0%
Graceton - Manor	Peak	9,505	9,247	97%	116	1%	1%
	Off Peak	13,554	13,117	97%	191	1%	1%
Jordan - West Frankfort	Peak	3,162	0	0%	0	0%	0%
	Off Peak	5,751	0	0%	0	0%	0%
Prest - Tibb	Peak	1,579	0	0%	0	0%	0%
	Off Peak	3,594	0	0%	0	0%	0%
Dresden	Peak	9,740	1,383	14%	9	0%	1%
	Off Peak	5,391	547	10%	14	0%	3%
Haumesser Road - Steward	Peak	6,813	32	0%	0	0%	0%
	Off Peak	7,010	66	1%	6	0%	9%
Chapparal - Carson	Peak	7,377	4,971	67%	5	0%	0%
	Off Peak	3,330	2,631	79%	15	0%	1%

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. 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.

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.[176]

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

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

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

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. This strategy is called crossing curves, or markup switching. Figure 3-63 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.

176 See OA Schedule 1 § 6.4.1(g).

Figure 3-63 Offers with varying markups at different MW output levels

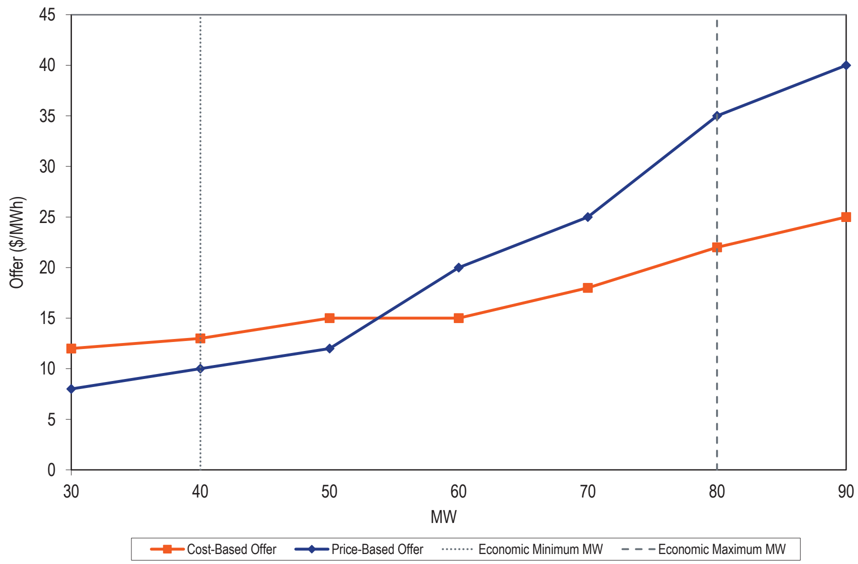


Table 3-106 shows the number and percent of unit schedule hours, by month, when unit offers included crossing curves (markup switch) in the PJM Day-Ahead and Real-Time Energy Markets in the first nine months of 2025. The analysis only includes units that offer both price-based and cost-based offers. Units in PJM are only required to submit cost-based offers, but they may elect to offer price-based offers.

Table 3-106 Units offered with crossing curves (markup switch): January through September, 2025

	Day-Ahead			Real-Time		
2025	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	81,057	889,896	9.1%	70,170	825,887	8.5%
Feb	78,904	807,696	9.8%	66,806	743,801	9.0%
Mar	81,963	891,245	9.2%	57,807	771,283	7.5%
Apr	78,129	866,880	9.0%	53,377	689,439	7.7%
May	85,949	897,984	9.6%	65,180	769,981	8.5%
Jun	88,261	858,504	10.3%	77,316	794,672	9.7%
Jul	98,474	889,848	11.1%	86,845	832,949	10.4%
Aug	96,152	890,040	10.8%	81,782	827,888	9.9%
Sep	91,581	866,904	10.6%	75,843	768,015	9.9%
Total	780,470	7,858,997	9.9%	635,126	7,023,915	9.0%

Table 3-107 shows the percent of unit schedule hours offered with crossing curves (markup switch), their average markup, their MW output weighted markup, and their average marginal unit LMP and markup contribution, when units failed the three pivotal supplier test in the PJM Day-Ahead Market and were marginal in the Real-Time Energy Market in the first nine months of 2025. The analysis only includes units that offer both price-based and cost-based offers.

Table 3-107 Marginal units offered with crossing curves (markup switch) and local market power: January through September, 2022 through 2025

	Unit hours with Crossing Curves Committed on Price Offer and Eligible for Offer-Capping DA and Marginal in Real-Time						
Year (Jan-Sep)	Percent of Unit hours with Crossing Curves	Average Markup Day-Ahead	Average Markup Real-Time	Load-Weighted Average Markup Day-Ahead	Load-Weighted Average Markup Real-Time	Average Marginal Unit LMP Contribution	Average Marginal Unit Markup Contribution
2022	12.7%	$14.40	$8.26	$17.21	$12.60	$3.45	$0.47
2023	12.1%	$10.24	$3.23	$11.71	$5.25	$1.37	$0.17
2024	12.3%	$9.27	$3.34	$10.61	$5.54	$1.32	$0.14
2025	18.2%	$11.46	$9.17	$14.46	$13.66	$1.68	$0.27

Table 3-108 shows the percent of unit schedule hours offered with crossing curves (markup switch), their average markup, their MW output weighted markup, and their average marginal unit LMP and markup contribution, when units failed the three pivotal supplier test in the PJM Day-Ahead Market, were marginal in the Real-Time Energy Market and had a negative markup in the PJM Day-Ahead Market in the first nine months of 2025. The analysis only includes units that offer both price-based and cost-based offers.

Table 3-108 Marginal units offered with crossing curves (markup switch), local market power and negative markup day-ahead: January through September, 2022 through 2025

	Unit hours with Crossing Curves Committed on Price Offer with Negative Markup and Eligible for Offer-Capping DA and Marginal with Positive Markup in Real-Time						
Year (Jan-Sep)	Percent of Unit hours with Crossing Curves	Average Markup Day-Ahead	Average Markup Real-Time	Load-Weighted Average Markup Day-Ahead	Load-Weighted Average Markup Real-Time	Average Marginal Unit LMP Contribution	Average Marginal Unit Markup Contribution
2022	2.0%	($8.20)	$20.83	($7.89)	$25.20	$3.73	$0.77
2023	2.7%	($3.16)	$10.54	($2.90)	$12.19	$1.22	$0.24
2024	2.6%	($3.48)	$11.37	($3.03)	$13.04	$1.47	$0.42
2025	3.7%	($3.98)	$23.24	($2.74)	$30.97	$1.69	$0.38

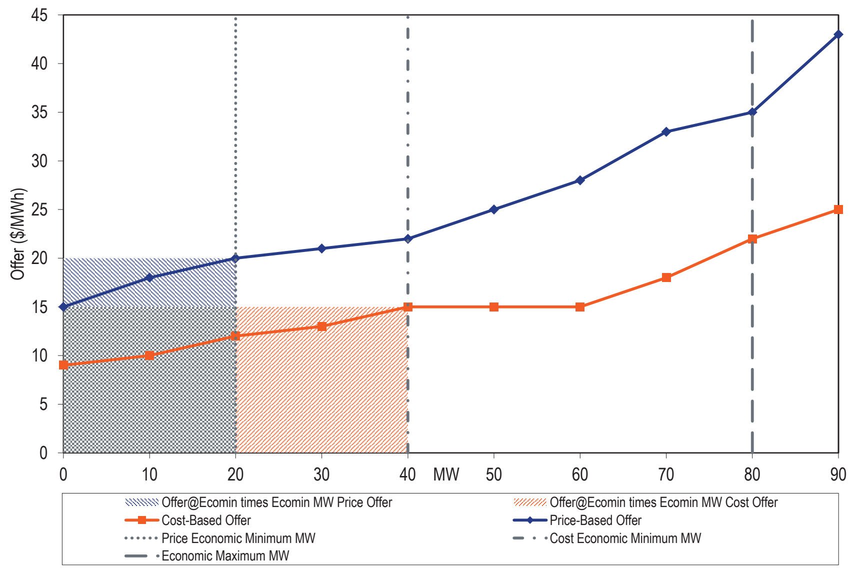
Offering a different economic minimum MW level, different minimum run times, or different start up and notification times in the cost-based and price-based offers can also be used to evade mitigation. For example, a unit may have a price-based offer with a positive markup, but have a shorter minimum 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 3-109 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 3-109 Units offered with lower minimum run time on price compared to cost and with positive markup: January through September, 2025

	Day-Ahead			Real-Time		
2025	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	2,733	889,896	0.3%	2,424	825,887	0.3%
Feb	2,634	807,696	0.3%	2,769	743,801	0.4%
Mar	10,697	891,245	1.2%	2,411	771,283	0.3%
Apr	5,914	866,880	0.7%	2,342	689,439	0.3%
May	4,752	897,984	0.5%	1,731	769,981	0.2%
Jun	1,704	858,504	0.2%	2,292	794,672	0.3%
Jul	2,148	889,848	0.2%	2,097	832,949	0.3%
Aug	2,395	890,040	0.3%	2,400	827,888	0.3%
Sep	2,256	866,904	0.3%	2,256	768,015	0.3%
Total	35,233	7,858,997	0.4%	20,722	7,023,915	0.3%

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 3-64 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 3-64 Offers with a positive markup but different economic minimum MW



The behavior in which 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 is limited to a number of units that does not permit data to be provided under the PJM confidentiality rules in both the day-ahead and real-time energy markets.

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 3-65 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 3-110 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 2025.

Figure 3-65 Dual fuel unit offers

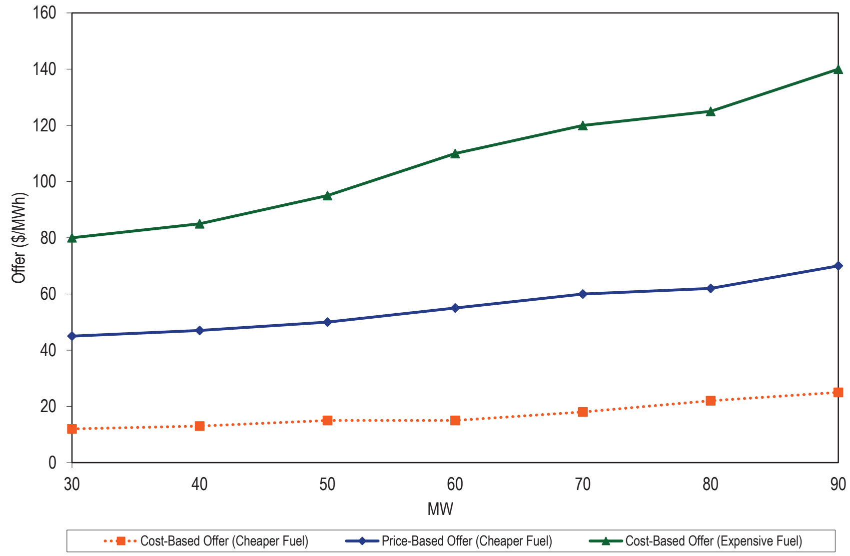


Table 3-110 Dual fuel unit offers with cost-based offers exceeding price-based offers (negative markup) but different fuel: January through September, 2025

	Day-Ahead			Real-Time		
2025	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	6,173	204,096	3.0%	6,173	202,973	3.0%
Feb	7,185	187,416	3.8%	7,185	182,810	3.9%
Mar	4,447	208,474	2.1%	4,447	184,434	2.4%
Apr	10,077	196,488	5.1%	10,077	160,603	6.3%
May	9,642	203,280	4.7%	9,642	184,120	5.2%
Jun	12,369	194,568	6.4%	12,369	183,501	6.7%
Jul	14,535	206,472	7.0%	14,535	197,708	7.4%
Aug	14,927	204,216	7.3%	14,927	196,591	7.6%
Sep	11,465	193,488	5.9%	11,465	178,980	6.4%
Total	90,820	1,798,498	5.0%	90,820	1,671,720	5.4%

These issues can be solved by simple rule changes.[177] 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.[178]

PJM filed and, on October 25, 2024, FERC accepted a revised proposal that would require that sellers that fail the TPS test will be offer capped at their cost-based offers and that operating parameters will be mitigated. However, PJM has no plans to implement the improved rules, so the flawed rules remain in place. PJM's proposal also uses the flawed formula rejected by FERC to select among cost-based offers. This will result in the illogical selection of cost-based offers in some circumstances, particularly if a dual fuel unit submits offers for both oil and gas on a day when the economics change between the two fuels midday. PJM should modify its implementation to address that issue. The result would allow market sellers to select the correct cost-based fuel schedule. There is no reason to delay implementation until PJM addresses combined cycle modelling. The changes would decrease the solution time for the day-ahead market and enhance market efficiency. The new approach should be implemented as soon as possible to help ensure effective market power mitigation.

The issues with offer capping will continue to allow the exercise of market power to affect prices until PJM implements the new approach. Currently, there is no implementation date. The simplified schedule selection process would shorten the time required to reach the day-ahead market solution, which is a market efficiency gain regardless of whether PJM implements combined cycle modelling. The MMU recommends that PJM commit all resources that fail the TPS test on their cost-based offers and that PJM implement that solution as soon as possible.[179]

Levels of offer capping have historically been low in PJM, as shown in Table 3-112. 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

177 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.

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

179 See "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>.

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.[180] 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 by PJM.

The offer capping percentages shown in Table 3-111 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.[181] 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 3-111 Offer capping statistics – energy only: January through September, 2018 to 2025

	Real-Time		Day-Ahead	
Year (Jan - Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2018	1.1%	0.5%	0.1%	0.2%
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	1.4%	1.1%	1.4%	1.0%
2023	1.3%	1.0%	1.6%	0.7%
2024	1.5%	1.0%	2.0%	1.0%
2025	1.4%	1.1%	1.9%	1.0%

180 See OA Schedule 1 § 6.4.1.

181 Prior to the *2018 Quarterly State of the Market Report for PJM: January through June*, these tables presented the offer cap percentages based on total bid unit hours and total load MWh. Beginning with the quarterly report for January through June, 2018, the statistics have been updated with percentages based on run hours and total generation MWh from units modeled in the energy market.

Table 3-112 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 3-113. 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. They are included in the offer capping percentages in Table 3-111. 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 3-113.

Table 3-112 Offer capping statistics for energy and reliability: January through September, 2018 to 2025

	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%
2024	1.7%	1.4%	2.2%	1.4%
2025	1.5%	1.3%	2.1%	1.2%

Table 3-113 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 consistent with that fact.[182]

182 OA Schedule 1, Section 6.4.1.

Table 3-113 Offer capping statistics for reliability: January through September, 2018 to 2025

	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%
2024	0.18%	0.38%	0.23%	0.42%
2025	0.10%	0.23%	0.12%	0.24%

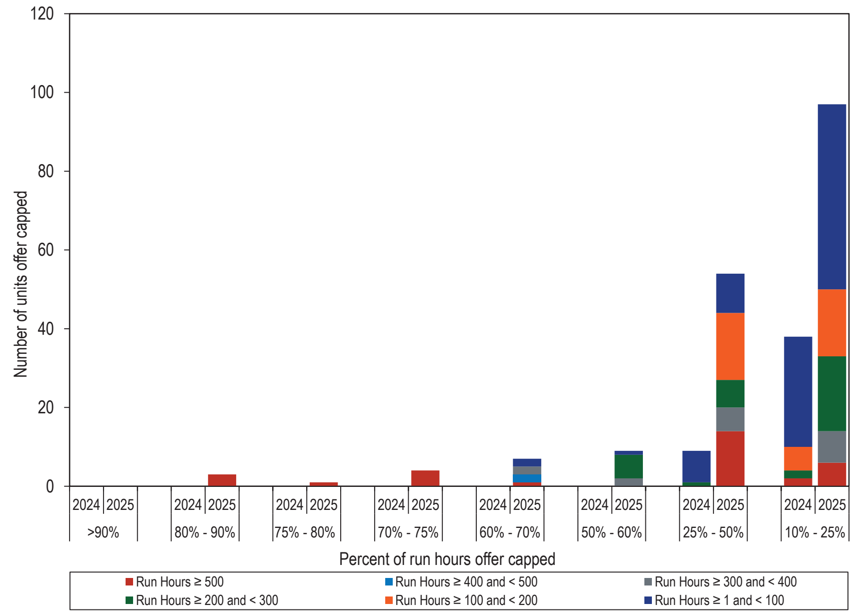
Table 3-114 presents data on the frequency with which units were offer capped in the first nine months of 2024 and 2025 as a result of failing the TPS test to provide energy for constraint relief in the real-time energy market, or for reliability reasons.

Table 3-114 Real-time offer capped unit statistics: January through September, 2024 and 2025

		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
	2024	0	0	0	0	0	0
90%	2025	0	0	0	0	0	0
	2024	0	0	0	0	0	0
80% and < 90%	2025	3	0	0	0	0	0
	2024	0	0	0	0	0	0
75% and < 80%	2025	1	0	0	0	0	0
	2024	0	0	0	0	0	0
70% and < 75%	2025	4	0	0	0	0	0
	2024	0	0	0	0	0	0
60% and < 70%	2025	1	2	2	0	0	2
	2024	0	0	0	0	0	0
50% and < 60%	2025	0	0	2	6	0	1
	2024	0	0	0	1	0	8
25% and < 50%	2025	14	0	6	7	17	10
	2024	2	0	0	2	6	28
10% and < 25%	2025	6	0	8	19	17	47

Figure 3-66 shows the frequency with which units were offer capped in the first nine months of 2024 and 2025 for failing the TPS test to provide energy for constraint relief in the real-time energy market or for reliability reasons.

Figure 3-66 Real-time offer capped unit statistics: January through September, 2024 and 2025



In response to FERC's request for Common Metrics for 2019 through 2022, which were published in FERC's 2023 Common Metrics Staff report, 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 1.6 percent.[183] [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

183 See Common Performance Metrics, Docket No. AD19-16-000, PJM Compliance Filing, PJM Metrics Spreadsheet 2023 (April 17, 2023).
184 See 2023 Common Metrics: Performance Metrics for ISOs, RTOs, and Regions Outside ISOs and RTOs for the Reporting Period 2019 to 2022, FERC Staff Report (January 31, 2024), <https://elibrary.ferc.gov/eLibrary/filelist?accession_num=20240131-4000>.

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.

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 3-115 shows the average markup index of marginal units in the real-time energy market, by offer price category using unadjusted cost-based offers. Table 3-116 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 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]

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.

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. 47 (Oct. 1, 2025).

In the first nine months of 2025, the average dollar markup of units with offer prices less than $10 was negative (-$5.20 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $10 and $15 was negative (-$2.32 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 2025, 2.9 percent had offer prices above $150 per MWh. Among the units that were marginal in the first nine months of 2024, 1.4 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 2025 was more than $900, and the highest markup in the first nine months of 2024 was more than $900.

Table 3-115 Real-time average marginal unit markup index (By offer price category unadjusted): January through September, 2024 and 2025

	2024 (Jan - Sep)			2025 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	(0.14)	($1.50)	29.2%	(0.28)	($5.20)	17.0%
$10 to $15	(0.10)	($1.81)	18.3%	(0.13)	($2.32)	6.3%
$15 to $20	(0.10)	($2.92)	14.8%	(0.09)	($2.15)	13.8%
$20 to $25	(0.05)	($2.77)	12.0%	(0.07)	($2.11)	16.1%
$25 to $50	0.03	($1.89)	19.2%	(0.03)	($2.49)	34.3%
$50 to $75	0.14	$7.04	3.5%	0.05	$0.30	6.6%
$75 to $100	0.21	$14.90	0.9%	0.14	$11.09	1.7%
$100 to $125	0.32	$33.71	0.4%	0.19	$19.92	0.7%
$125 to $150	0.25	$35.26	0.2%	0.16	$20.36	0.5%
>= $150	0.12	$25.64	1.4%	0.07	$17.99	2.9%
All Offers	(0.06)	($0.93)	100.0%	(0.07)	($1.53)	100.0%

Table 3-117 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]

Table 3-116 Real-time average marginal unit markup index (By offer price category adjusted): January through September, 2024 and 2025

	2024 (Jan - Sep)			2025 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	(0.10)	($1.02)	29.2%	(0.28)	($4.81)	17.0%
$10 to $15	(0.03)	($0.73)	18.3%	(0.06)	($1.14)	6.3%
$15 to $20	(0.04)	($1.56)	14.8%	(0.02)	($0.54)	13.8%
$20 to $25	0.01	($1.10)	12.0%	0.00	($0.16)	16.1%
$25 to $50	0.09	$0.53	19.2%	0.04	$0.38	34.3%
$50 to $75	0.19	$10.33	3.5%	0.11	$4.60	6.6%
$75 to $100	0.25	$19.20	0.9%	0.20	$16.11	1.7%
$100 to $125	0.35	$37.06	0.4%	0.24	$25.40	0.7%
$125 to $150	0.28	$39.03	0.2%	0.21	$27.37	0.5%
>= $150	0.18	$40.86	1.4%	0.14	$37.34	2.9%
All Offers	(0.00)	$0.67	100.0%	(0.01)	$1.14	100.0%

Table 3-118 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 2025, using unadjusted cost-based offers for coal units, 47.89 percent of marginal coal units had negative markups. The share of marginal coal units with negative markups at the dispatch point on their offer curve decreased from 60.08 percent in the first nine months of 2024 to 47.89 percent in the first nine months of 2025 when using unadjusted cost based offers.

Table 3-117 Percent of marginal units with markup below, above and equal to zero (By fuel type with unadjusted offers): January through September, 2024 and 2025

	2024 (Jan - Sep)			2025 (Jan - Sep)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	60.08%	27.04%	12.88%	47.89%	32.05%	20.06%
Gas	63.26%	16.78%	19.95%	65.47%	18.42%	16.11%
Oil	10.26%	88.05%	1.69%	16.44%	80.80%	2.76%

In the first nine months of 2025, using adjusted cost-based offers for coal units, 33.82 percent of marginal coal units had negative markups.

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

Table 3-118 Percent of marginal units with markup below, above and equal to zero (By fuel type with adjusted offers): January through September, 2024 and 2025

	2024 (Jan - Sep)			2025 (Jan - Sep)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	49.81%	9.42%	40.77%	33.82%	8.79%	57.40%
Gas	45.03%	10.93%	44.04%	33.17%	11.11%	55.72%
Oil	9.85%	87.50%	2.64%	15.51%	79.59%	4.90%

Figure 3-67 shows the frequency distribution of hourly markups for all gas units offered in the first nine months of 2024 and the first nine months of 2025 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 2025, 18.2 percent of gas unit hours had a maximum markup that was negative and 23.6 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 decreased in the first nine months of 2025 compared to the first nine months of 2024, while the share of marginal gas units with negative markups at the dispatch point increased.

Figure 3-67 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: January through September, 2024 and 2025

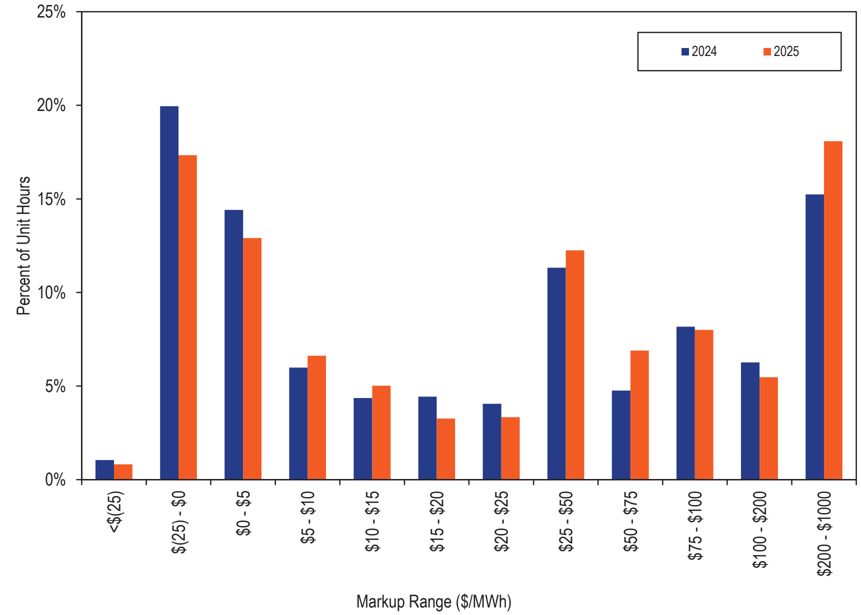


Figure 3-68 shows the frequency distribution of hourly markups for all coal units offered in the first nine months of 2024 and the first nine months of 2025 using unadjusted cost-based offers. Of the coal units offered in the PJM market in the first nine months of 2025, 36.3 percent of coal unit hours had a maximum markup that was negative or equal to zero, increasing from 34.0 percent in the first nine months of 2024. The share of offered coal units with maximum markup that was negative increased in the first nine months of 2025, while the share of marginal coal units with negative markups at the dispatch point decreased in the first nine months of 2025 compared to the first nine months of 2024.

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

Figure 3-68 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: January through September, 2024 and 2025

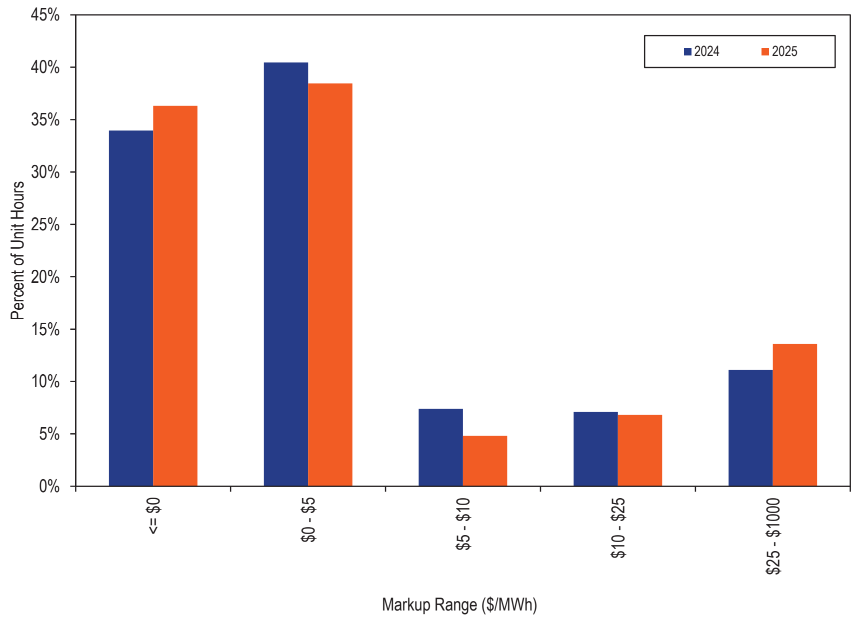
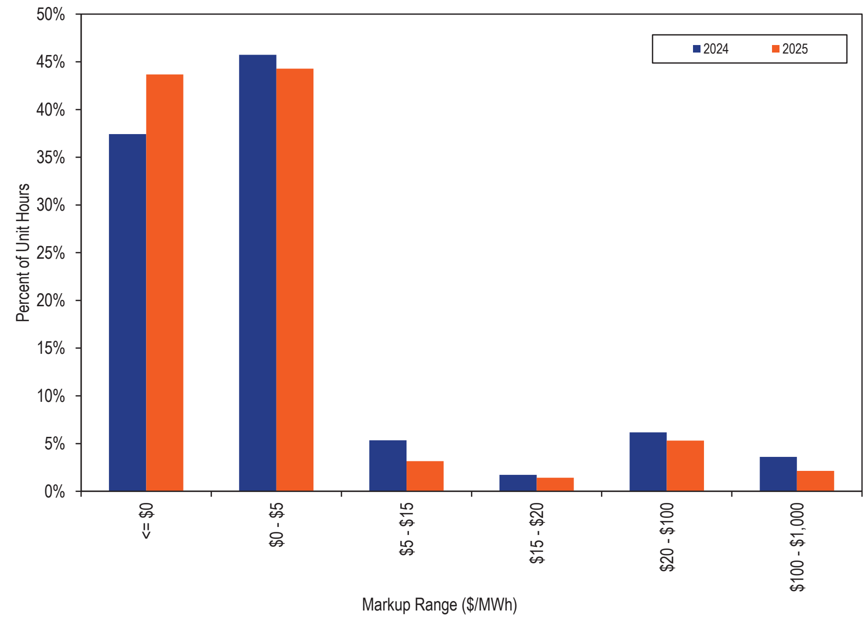


Figure 3-69 shows the frequency distribution of hourly markups for all offered oil units in the first nine months of 2024 and the first nine months of 2025 using unadjusted cost-based offers. Of the oil units offered in the PJM market in the first nine months of 2025, 43.7 percent of oil unit hours had a maximum markup that was negative or equal to zero. More than 2.1 percent of oil fired unit hours had a maximum markup above $100 per MWh.

Figure 3-69 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: January through September, 2024 and 2025

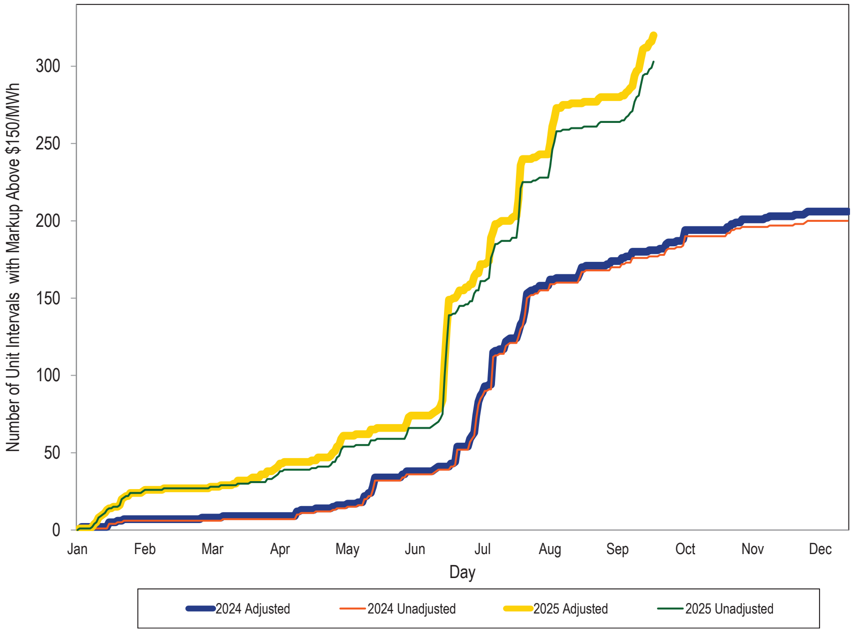


The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion 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 3-70 shows the number of marginal unit intervals in the first nine months of 2025 and 2024 with markup above $150 per MWh.

Figure 3-70 Cumulative number of unit intervals with markups above $150 per MWh: January 2024 through September 2025



Day-Ahead Markup Index

Table 3-119 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]

In the six months between April and September of 2025, the average dollar markup of units with offer prices less than $10 was positive ($6.63 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $10 and $15 was positive ($6.38 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 six months between April and September of 2025, 1.3 percent had offer prices above $150 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the six months between April and September of 2025 was more than $550 per MWh.

Table 3-119 Average day-ahead marginal unit markup index (By offer price category, unadjusted): April through September, 2025

	2025 (Apr - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency
< $10	2.15	$6.63	7.1%
$10 to $15	0.66	$6.38	9.1%
$15 to $20	0.11	$0.97	13.6%
$20 to $25	0.05	$0.41	15.0%
$25 to $50	0.09	$2.27	43.9%
$50 to $75	0.24	$14.74	7.2%
$75 to $100	0.23	$19.61	2.0%
$100 to $125	0.29	$31.22	0.6%
$125 to $150	0.32	$45.19	0.1%
>= $150	0.27	$76.94	1.3%
All Offers	0.23	$4.96	100.0%

190 MMU identified an error in the marginal resource identification algorithm within the day ahead clearing optimization. The calculation of generator sensitivity factors and markup index require accurate identification of marginal resources. The error was fixed by the PJM software vendor in March 2025. MMU was unable to calculate markup index for 2024 and the first quarter of 2025 due to the inaccurate identification of marginal resources.

Table 3-120 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using adjusted cost-based offers.

Table 3-120 Average day-ahead marginal unit markup index (By offer price category, adjusted): April through September, 2025

	2025 (Apr - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency
< $10	2.18	$6.85	7.1%
$10 to $15	0.73	$7.32	9.1%
$15 to $20	0.18	$2.51	13.6%
$20 to $25	0.11	$2.21	15.0%
$25 to $50	0.16	$4.82	43.9%
$50 to $75	0.29	$17.71	7.2%
$75 to $100	0.27	$22.89	2.0%
$100 to $125	0.32	$35.06	0.6%
$125 to $150	0.34	$47.62	0.1%
>= $150	0.30	$87.37	1.3%
All Offers	0.29	$7.10	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 3-121 shows the caps on the three parts of cost-based and price-based offers.

Table 3-121 Cost-based and price-based offer caps

<table>
<tr><th>Offer Type</th><th>No Load and Start Cost Option</th><th>Incremental Offer Curve Cap</th><th>No Load Cost Cap</th><th>Start Cost Cap</th></tr>
<tr><td>Cost-Based</td><td>Cost-Based</td><td colspan="3">Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies</td></tr>
<tr><td rowspan="2">Price-Based</td><td>Cost-Based</td><td rowspan="2">$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.</td><td>Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies</td><td>Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies</td></tr>
<tr><td>Price-Based</td><td>No cap but can only be changed twice a year.</td><td>No cap but can only be changed twice a year.</td></tr>
</table>

Table 3-122 shows the number of units that chose the cost-based option and the price-based option. In the first nine months of 2025, 90 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 2024.

Table 3-122 Number of units selecting cost-based and price-based no load and start costs: January through September, 2024 and 2025

No Load and Start Cost Option	2024 (Jan-Sep) Number of units	Percent	2025 (Jan-Sep) Number of units	Percent
Cost-Based	480	90%	468	90%
Price-Based	51	10%	50	10%
Total	531	100%	518	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 3-123 shows the average markup in the no load and start costs in the first nine months of 2024 and 2025. 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. In the first nine months of 2025, 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 3-123 No load and start cost markup: January through September, 2024 and 2025

Period	No Load and Start Cost Option	No Load Cost	Cold Start Cost	Intermediate Start Cost	Hot Start Cost
2024 (Jan-Sep)	Cost-Based	(8%)	(6%)	(6%)	(7%)
	Price-Based	10%	197%	183%	186%
2025 (Jan-Sep)	Cost-Based	(14%)	(5%)	(5%)	(7%)
	Price-Based	23%	139%	123%	122%

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 2025, 9.8 percent of the marginal units set prices based on cost-based offers, 2.3 percentage points higher than in the first nine months of 2024.

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.

191 See 167 FERC ¶ 61,030 (2019).
192 See OA Schedule 2 § 1.1(a).

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

The MMU recommends that PJM require that the level of costs includable in cost-based offers 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 3-124 shows the status of all fuel cost policies (FCP). As of September 30, 2025, 715 units (92 percent) had an FCP passed by the MMU and 65 units (eight percent) had an FCP failed by the MMU. The units with fuel cost policies failed by the MMU represented 15,740 MW. All units’ FCPs were approved by PJM. As of September 30, 2025, 612 units did not have FCPs. Units without FCPs cannot submit nonzero cost based offers, unless they use the temporary cost method.[193]

Table 3-124 FCP Status for PJM generating units: September 30, 2025

	MMU Status				Units without
PJM Status	Pass	Submitted	Fail	Total	FCPs
Approved	715	0	65	780	
Rejected	0	0	0	0	
Under Review	0	0	0	0	
Customer Input Required	0	0	0	0	
Submitted	0	0	0	0	
Total	715	0	65	780	612

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

193 See OA Schedule 2 § 2.1.

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]

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.

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.

Units are required to have an approved fuel cost policy before they can submit nonzero cost-based offers or request from PJM the use of a temporary cost method. The temporary cost offer method allows 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, allowing the use of an inaccurate and unsupported fuel cost calculation in place of an accurate fuel cost policy.

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.
198 See PJM Operating Agreement Schedule 2 § 2.3 (a).

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.

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 2025, 28 penalty cases were identified, 27 have been assessed cost-based offer penalties and one remains pending. These cases were for 28 units owned by 11 different companies. Table 3-125 shows the penalties by the year in which participants were notified.

Table 3-125 Cost-based offer penalty cases by year notified: May 2017 through September 2025

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	65	65	13	0	0	61	18
2024	77	77	39	0	0	67	21
2025	28	27	2	0	1	28	11
Total	858	820	171	37	1	516	81

Since 2017, of the 858 penalty cases, 820 resulted in assessed cost-based offer penalties, 37 resulted in disagreement between the MMU and PJM and one remains pending. A total of 171 were self identified by market sellers. The 820 cases were from 516 units owned by 81 different companies. The total penalties were $6.0 million, charged to units that totaled 165,275 available MW. The average penalty was $1.60 per available MW. This means that a 100 MW unit would have paid a penalty of $3,840.[200] There is no link between the increased costs to the market that result from a penalized fuel cost policy and the amount of the penalty. The increased costs to the market can exceed the penalty payment and the reverse can also be true. Table 3-126 shows the total cost-based offer penalties since 2017 by year.

Table 3-126 Cost-based offer penalties by year: May 2017 through September 2025

Year	Number of units	Number of companies	Penalties	Average Available Capacity Charged (MW)	Average Penalty ($/MW)
2017	92	21	$556,826	16,930	$1.56
2018	127	35	$1,242,102	25,743	$2.28
2019	73	24	$378,245	15,073	$1.14
2020	140	28	$407,283	21,908	$0.85
2021	125	27	$753,463	24,808	$1.31
2022	123	22	$1,613,621	24,385	$2.76
2023	61	16	$333,948	10,383	$1.33
2024	79	22	$549,736	21,900	$1.05
2025	27	10	$181,937	4,145	$1.84
Total	847	78	$6,017,161	165,275	$1.60

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.

Penalties do not apply when PJM determines that an unforeseen event hindered the market seller's ability to submit a compliant cost-based offer. This 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. This practice is inappropriate and should stop.

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.

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.

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 for thermal resources. 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.[201]

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.[202] 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, subject to revisions requested by FERC.[203] On October 28, 2019, FERC issued a final order accepting PJM's compliance filing.[204] 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.

201 See PJM Manual 15: Cost Development Guidelines, Revision 47 (Oct. 1, 2025).
202 See PJM Interconnection Maintenance Adder Revisions to the Amended and Restated Operating Agreement, L.L.C., Docket No. EL19-8-000.
203 167 FERC ¶ 61,030 (2019).
204 168 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 2024.

Table 3-127 shows the average VOM by unit type. The VOM equals the sum of variable operating cost, major maintenance adder and minor maintenance adder as submitted by market participants.

Table 3-127 Effective VOM costs in dollars per MWh in 2024

Unit Type	VOM ($/MWh)
Combined Cycles	$3.00
Combustion Turbines and RICE	$22.62
Gas/Oil Steam Turbines	$12.19
Coal	$6.01

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 ten years ago without any supporting documentation as long as the data from the current year has documentation. PJM's review is dependent on the level of detail provided by the market seller. As a result of questions raised by the MMU, PJM now requires more details from market sellers, which has led to the appropriate exclusion of expenses that were previously included.[205]

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.

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. Table 3-128 shows the default adders for operating cost and minor maintenance.

Table 3-128 Default operating cost and minor maintenance adder: 2024

Unit Type	Operating Cost ($/MWh)	Minor Maintenance Cost ($/MWh)
Combined Cycle	0.46	1.13
Combustion Turbine	0.86	4.14
Reciprocating Engine	1.87	4.64
Steam Turbine	3.31	1.97

205 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 recommended 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 revisions to Manual 15 based on the February 17, 2023, filing included this requirement.

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 revisions to Manual 15 based on the February 17, 2023, filing partially included this requirement. Even though Manual 15 requires maintenance expenses to be the result of operating hours, starts or a combination of the two, the expenses are not tied to a maintenance cycle. Therefore, it is not possible to distinguish between maintenance that resulted from operating the resource versus maintenance from normal wear and tear.

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.

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.[206]

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 cost-based offers. The changes were approved by the Commission on January 10, 2023 and became effective on June 1, 2023.[207]

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.[208] 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.[209]

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

206 The peak adder is equal to $300 times three divided by 5 MW.
207 *See* Federal Energy Regulatory Commission, Docket No. ER23-557-000 (January 10, 2023) at 1.
208 *See* "Start Cost Alternate Proposal," MMU presentation to the Cost Development Subcommittee. (December 2, 2021) <20211202-item-06-start-cost-alternate-proposal.ashx>.
209 *See* Federal Energy Regulatory Commission, Docket No. ER23-557-000 (January 10, 2023) at 1.

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 reasons, 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.[210] 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, 2023, and 2024, no units qualified for an FMU adder. In the first nine months of 2025, no units qualified for an FMU adder.

Table 3-129 shows, by month, the number of FMUs and AUs from January 2021 through September 2025. 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.

210 For a definition of FMUs and AUs, and for historical FMU/AU results, see the *2018 Annual State of the Market Report for PJM*, Volume 2, Section 3, Energy Market, at Frequently Mitigated Units (FMU) and Associated Units (AU).

Table 3-129 Number of frequently mitigated units and associated units (By month): January 2021 through September 2025

	2021				2022				2023				2024				2025			
	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	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	0	0	0	0	0	0	0	0
February	0	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0	0
June	0	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0	0
August	0	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0	0
October	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
November	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
December	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				

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 3-130 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.[211] 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 2025, and summed by the parent company that offers the marginal resource into the real-time energy market. In the first nine months of 2025, the offers of one company resulted in 16.3 percent of the real-time load-weighted PJM system LMP and the offers of the top four companies resulted in 40.8 percent of the real-time load-weighted average PJM system LMP. In the first nine months of 2025, the offers of one company resulted in 15.0 percent of the peak hour real-time load-weighted PJM system LMP.

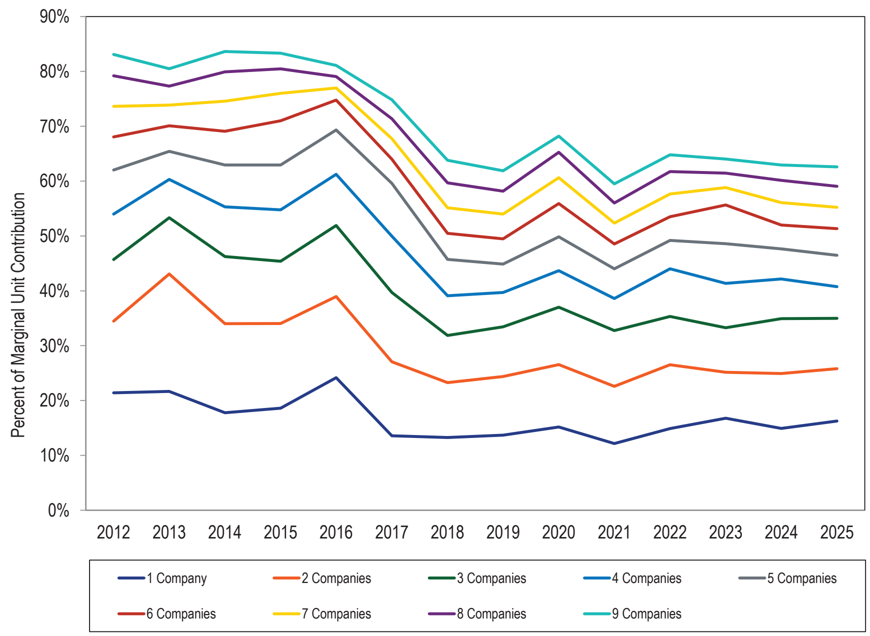
211 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table 3-130 Marginal unit contribution to real-time load-weighted LMP (By parent company): January through September, 2024 and 2025

2024 (Jan - Sep)						2025 (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	15.8%	15.8%	1	16.3%	16.3%	1	15.0%	15.0%
2	10.0%	24.9%	2	12.7%	28.5%	2	9.5%	25.8%	2	10.1%	25.1%
3	10.0%	34.9%	3	8.3%	36.8%	3	9.2%	35.0%	3	7.3%	32.5%
4	7.3%	42.2%	4	7.1%	43.9%	4	5.8%	40.8%	4	5.2%	37.6%
5	5.5%	47.6%	5	4.7%	48.6%	5	5.7%	46.5%	5	5.1%	42.8%
6	4.3%	52.0%	6	4.5%	53.1%	6	4.8%	51.3%	6	4.9%	47.7%
7	4.1%	56.1%	7	3.9%	57.1%	7	3.9%	55.2%	7	4.8%	52.5%
8	4.1%	60.1%	8	3.8%	60.8%	8	3.8%	59.0%	8	4.6%	57.1%
9	2.8%	62.9%	9	3.0%	63.9%	9	3.6%	62.6%	9	4.3%	61.4%
Other (93 companies)	37.1%	100.0%	Other (89 companies)	36.1%	100.0%	Other (104 companies)	37.4%	100.0%	Other (100 companies)	38.6%	100.0%

Figure 3-71 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 3-71 Marginal unit contribution to real-time load-weighted LMP (By parent company): January through September, 2012 through 2025



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.[212] 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.

212 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 3-131 shows the impact (markup component of LMP) of the marginal unit markup behavior by fuel type and unit type on the real-time load-weighted average system LMP using unadjusted and adjusted offers. The adjusted markup component of LMP increased from $2.28 per MWh in the first nine months of 2024 to $2.95 per MWh in the first nine months of 2025. The adjusted markup contribution of coal units in the first nine months of 2025 was $0.64 per MWh, an increase of $0.40 per MWh from the first nine months of 2024. The adjusted markup component of gas fired units in the first nine months of 2025 was $2.93 per MWh, an increase of $0.43 per MWh from the first nine months of 2024. 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 2025, among the wind units that were marginal, 68.7 percent had negative offer prices.

Table 3-131 Markup component of real-time load-weighted average LMP by primary fuel type and unit type: January through September, 2024 and 2025[213]

		2024 (Jan - Sep)		2025 (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	($0.24)	$0.24	$0.23	$0.64
Gas	CC	$1.01	$1.83	$0.54	$2.00
Gas	CT	$0.13	$0.61	$0.12	$0.91
Gas	RICE	($0.01)	$0.01	$0.03	$0.05
Gas	Steam	($0.02)	$0.05	($0.15)	($0.04)
Municipal Waste	RICE	$0.01	$0.01	$0.02	$0.02
Oil	CC	($0.00)	($0.00)	($0.00)	$0.01
Oil	CT	($0.52)	($0.44)	($0.91)	($0.72)
Oil	RICE	($0.00)	$0.00	$0.00	$0.01
Oil	Steam	($0.18)	($0.16)	($0.07)	($0.04)
Other	Battery	$0.00	$0.00	$0.01	$0.01
Other	Solar	$0.10	$0.10	$0.01	$0.01
Other		$0.01	$0.01	$0.07	$0.07
Wind		$0.02	$0.02	$0.01	$0.01
Total		$0.30	$2.28	($0.09)	$2.95

Markup Component of Real-Time Price

Table 3-132 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-133 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 2025, when using unadjusted cost-based offers, -$0.09 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-based offers, $2.94 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first nine months of 2025, the peak markup component was highest in July, $2.74 per MWh using unadjusted cost-based offers and $6.66 per MWh using adjusted cost-based offers. This corresponds to 3.5 percent and 8.6 percent of the real-time peak load weighted average LMP in July.

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

Table 3-132 Monthly markup components of real-time load-weighted LMP (Unadjusted): January 2024 through September 2025

	2024			2025		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	($3.81)	($2.55)	($5.05)	($2.00)	($1.17)	($2.83)
Feb	$0.12	$0.60	($0.36)	($0.22)	($0.59)	$0.15
Mar	($0.14)	($0.68)	$0.34	($0.37)	($1.02)	$0.22
Apr	$1.49	$2.00	$0.92	$0.68	$0.32	$1.07
May	($0.57)	($0.17)	($1.00)	($0.54)	($0.29)	($0.79)
Jun	($0.45)	($1.01)	$0.11	$0.29	($0.08)	$0.69
Jul	$3.72	$6.10	$1.11	$0.55	$2.74	($1.87)
Aug	$2.31	$4.47	($0.07)	($0.87)	($0.94)	($0.79)
Sep	($0.33)	($0.28)	($0.37)	$1.52	$1.48	$1.56
Oct	($1.60)	($1.64)	($1.56)			
Nov	($0.06)	$0.76	($0.81)			
Dec	($1.38)	($1.43)	($1.32)			
Total	($0.01)	$0.67	($0.70)	($0.09)	$0.12	($0.41)

Table 3-133 Monthly markup components of real-time load-weighted LMP (Adjusted): January 2024 through September 2025

	2024			2025		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	($0.78)	$0.62	($2.16)	$2.16	$3.38	$0.95
Feb	$1.77	$2.26	$1.28	$3.21	$3.08	$3.35
Mar	$1.29	$0.88	$1.66	$2.40	$1.79	$2.94
Apr	$3.03	$3.65	$2.35	$3.53	$3.24	$3.85
May	$1.38	$2.00	$0.72	$1.68	$2.16	$1.20
Jun	$1.50	$1.28	$1.72	$3.34	$3.47	$3.21
Jul	$6.03	$8.87	$2.91	$4.01	$6.66	$1.08
Aug	$4.15	$6.54	$1.51	$1.72	$2.08	$1.37
Sep	$1.48	$1.72	$1.25	$3.86	$4.05	$3.66
Oct	$0.24	$0.38	$0.08			
Nov	$1.79	$2.79	$0.88			
Dec	$0.98	$1.06	$0.90			
Total	$1.98	$2.86	$1.08	$2.94	$3.46	$2.31

Hourly Markup Component of Real-Time Prices

Figure 3-72 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in the first nine months of 2025 and 2024. Figure 3-73 shows the markup contribution to the hourly load-weighted LMP using adjusted cost-based offers in the first nine months of 2025 and 2024.

Figure 3-72 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): January 2024 through September 2025

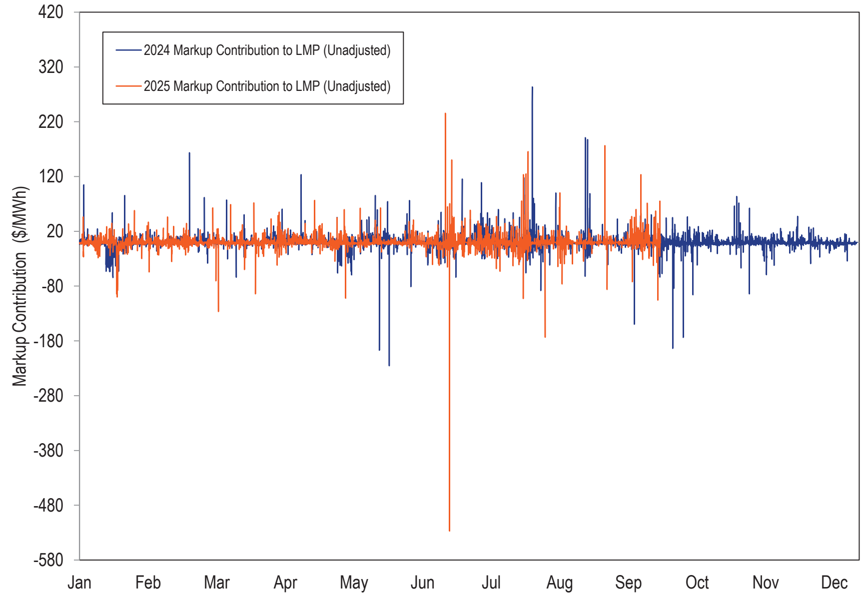
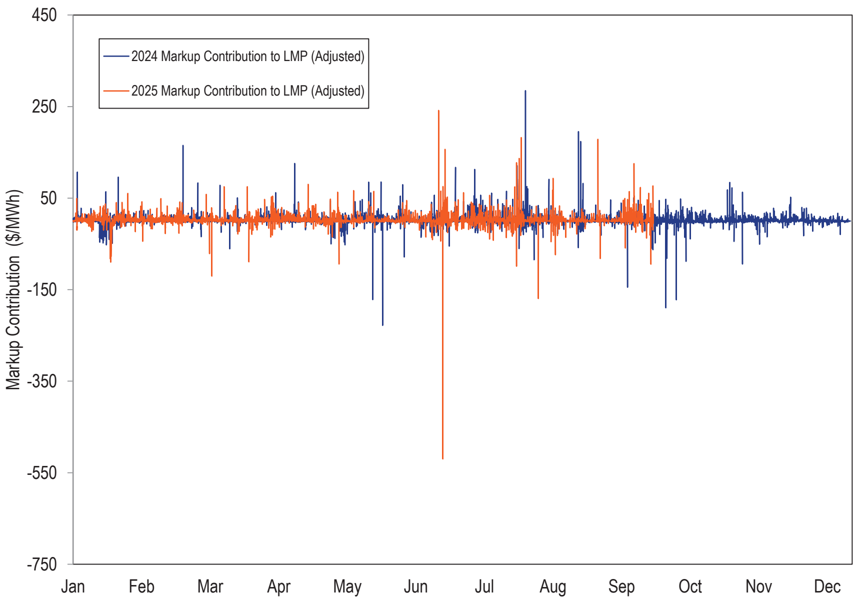


Figure 3-73 Markup contribution to real-time hourly load-weighted LMP (Adjusted): January 2024 through September 2025



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 2024 and 2025 in Table 3-134 and for adjusted offers in Table 3-135.[214] The smallest zonal all hours average markup component using unadjusted offers in the first nine months of 2025, was in the DPL Zone, -$2.09 per MWh, while the highest was in the BGE Zone, $0.72 per MWh. The smallest zonal on peak average markup component using unadjusted offers in the first nine months of 2025, was in the DPL Zone, -$2.88 per MWh, while the highest was in the PE Zone, $1.23 per MWh.

214 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 3-134 Real-time average zonal markup component (Unadjusted): January through September, 2024 and 2025

	2024 (Jan - Sep)			2025 (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	($0.18)	$0.73	($1.11)	($1.61)	($2.12)	($1.09)
AEP	$0.49	$1.39	($0.43)	$0.17	$0.72	($0.38)
APS	$0.16	$0.93	($0.63)	$0.14	$0.53	($0.25)
ATSI	$0.29	$1.08	($0.53)	$0.05	$0.56	($0.45)
BGE	$1.80	$2.55	$1.02	$0.72	$0.78	$0.66
COMED	$0.26	$1.06	($0.56)	$0.23	$0.80	($0.35)
DAY	$0.14	$0.95	($0.70)	$0.01	$0.45	($0.43)
DOM	$0.69	$1.44	($0.08)	($0.06)	$0.09	($0.22)
DPL	($0.11)	$0.70	($0.94)	($2.09)	($2.88)	($1.29)
DUKE	($0.23)	$0.68	($1.17)	($0.01)	$0.41	($0.43)
DUQ	($0.02)	$0.58	($0.63)	$0.01	$0.55	($0.54)
EKPC	($0.16)	$0.59	($0.94)	($0.09)	$0.16	($0.34)
JCPLC	($0.32)	$0.61	($1.28)	($0.75)	($0.53)	($0.98)
MEC	($0.52)	$0.44	($1.51)	($0.73)	($0.36)	($1.11)
OVEC	($0.29)	$0.26	($0.84)	$0.15	$0.76	($0.46)
PE	($0.12)	$0.57	($0.82)	$0.62	$1.23	$0.00
PECO	($0.21)	$0.57	($1.02)	($1.69)	($2.25)	($1.12)
PEPCO	$1.11	$1.68	$0.53	$0.41	$0.19	$0.62
PPL	($0.62)	$0.18	($1.45)	($1.14)	($0.78)	($1.50)
PSEG	($0.23)	$0.80	($1.28)	($0.63)	($0.43)	($0.83)
REC	($0.11)	$0.70	($0.95)	$0.17	$0.27	$0.08

Table 3-135 Real-time average zonal markup component (Adjusted): January through September, 2024 and 2025

	2024 (Jan - Sep)			2025 (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	$1.54	$2.58	$0.47	$1.28	$1.07	$1.49
AEP	$2.47	$3.57	$1.33	$3.29	$4.15	$2.42
APS	$2.22	$3.23	$1.18	$3.34	$4.07	$2.59
ATSI	$2.29	$3.35	$1.21	$3.15	$3.99	$2.32
BGE	$4.17	$5.23	$3.09	$4.24	$4.69	$3.79
COMED	$2.05	$3.08	$1.00	$2.99	$3.93	$2.05
DAY	$2.16	$3.19	$1.09	$3.14	$3.89	$2.37
DOM	$2.91	$3.91	$1.88	$3.42	$3.99	$2.85
DPL	$1.74	$2.69	$0.76	$0.98	$0.61	$1.35
DUKE	$1.72	$2.84	$0.56	$3.03	$3.75	$2.30
DUQ	$2.00	$2.87	$1.11	$3.07	$3.96	$2.19
EKPC	$1.80	$2.76	$0.80	$2.99	$3.54	$2.44
JCPLC	$1.42	$2.47	$0.33	$2.15	$2.67	$1.62
MEC	$1.33	$2.51	$0.13	$2.23	$2.96	$1.49
OVEC	$1.62	$2.36	$0.85	$3.10	$4.00	$2.20
PE	$1.87	$2.79	$0.92	$3.77	$4.71	$2.83
PECO	$1.47	$2.39	$0.53	$1.13	$0.85	$1.40
PEPCO	$3.40	$4.25	$2.54	$3.85	$4.01	$3.70
PPL	$1.13	$2.12	$0.12	$1.70	$2.39	$1.01
PSEG	$1.52	$2.66	$0.34	$2.30	$2.80	$1.80
REC	$1.69	$2.61	$0.74	$3.24	$3.64	$2.84

Markup by Real-Time Price Levels

Table 3-136 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 3-136 Real-time markup contribution (By load-weighted LMP category, unadjusted): January through September, 2024 and 2025

	2024 (Jan - Sep)		2025 (Jan - Sep)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($1.96)	1.7%	($3.99)	0.1%
$10 to $15	($1.88)	13.7%	($2.23)	1.1%
$15 to $20	($2.31)	17.9%	($1.78)	7.8%
$20 to $25	($1.90)	17.4%	($1.91)	12.0%
$25 to $50	$0.09	37.7%	($1.65)	53.3%
$50 to $75	$5.04	6.9%	$0.71	15.5%
$75 to $100	$6.47	2.1%	$3.58	4.8%
$100 to $125	$5.95	1.2%	$10.08	2.2%
$125 to $150	$17.72	0.5%	$9.10	1.1%
>= $150	$34.25	0.8%	$11.76	2.0%

Table 3-137 Real-time markup contribution (By load-weighted LMP category, adjusted): January through September, 2024 and 2025

	2024 (Jan - Sep)		2025 (Jan - Sep)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($1.19)	1.7%	($2.84)	0.1%
$10 to $15	($0.83)	13.7%	($1.07)	1.1%
$15 to $20	($0.96)	17.9%	($0.29)	7.8%
$20 to $25	($0.28)	17.4%	($0.07)	12.0%
$25 to $50	$2.34	37.7%	$1.07	53.3%
$50 to $75	$8.01	6.9%	$4.43	15.5%
$75 to $100	$9.67	2.1%	$7.90	4.8%
$100 to $125	$9.84	1.2%	$14.63	2.2%
$125 to $150	$21.85	0.5%	$15.13	1.1%
>= $150	$37.36	0.8%	$19.23	2.0%

Markup by Company

Table 3-138 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 2025, when using unadjusted cost-based offers, the markup of one company accounted for 0.8 percent of the load-weighted average LMP, the markup of the top five companies accounted for 2.8 percent of the load-weighted average LMP and the markup of all companies accounted for -0.3 percent of the load-weighted average LMP. The share of top five companies' markup contribution to the load-weighted average LMP decreased and the dollar values of their markup decreased in the first nine months of 2025. 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 2025. The markup contribution of a unit to the real-time load-weighted average LMP can be positive or negative.

Table 3-138 Markup component of real-time load-weighted average LMP by Company: January through September, 2024 and 2025

	2024 (Jan - Sep)				2025 (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	$0.66	1.9%	$0.76	2.2%	$0.43	0.8%	$0.63	1.2%
Top 2 Companies	$0.99	2.9%	$1.25	3.6%	$0.82	1.6%	$1.19	2.4%
Top 3 Companies	$1.28	3.7%	$1.62	4.7%	$1.15	2.3%	$1.71	3.4%
Top 4 Companies	$1.50	4.4%	$1.97	5.7%	$1.39	2.8%	$2.21	4.4%
Top 5 Companies	$1.67	4.9%	$2.21	6.4%	$1.54	3.0%	$2.49	4.9%
All Companies	$0.29	0.9%	$2.28	6.7%	($0.15)	(0.3%)	$2.89	5.7%

Day-Ahead Markup[215]

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 3-139. INC, DEC and up to congestion transactions (UTC) have zero markups. The adjusted markup of coal, gas and oil units is calculated as the difference between the price-based offer and the cost-based offer excluding the 10 percent adder.

Table 3-139 shows the markup component of LMP for marginal generating resources. The adjusted markup component of LMP for coal fired units was $0.28 per MWh in the six months between April and September of 2025. The adjusted markup component of LMP for gas fired CC units was $1.38 per MWh in the six months between April and September of 2025.

215 MMU identified an error in the marginal resource identification algorithm within the day ahead clearing optimization. The calculation of generator sensitivity factors and markup index require accurate identification of marginal resources. The error was fixed by the PJM software vendor in March 2025. MMU was unable to calculate markup index for 2024 and the first quarter of 2025 due to the inaccurate identification of marginal resources.

Table 3-139 Markup component of day-ahead load-weighted average LMP by primary fuel type and technology type: April through September, 2025

		2025 (Apr - Sep)	
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($0.12)	$0.28
Gas	CC	$0.53	$0.96
Gas	CT	$0.32	$0.48
Gas	RICE	($0.00)	$0.00
Gas	Steam	($0.16)	($0.07)
Oil	CC	$0.00	$0.00
Oil	CT	($0.01)	($0.01)
Oil	RICE	$0.00	$0.00
Oil	Steam	($0.05)	($0.04)
Other	Solar	$1.42	$1.42
Other	Steam	$0.01	$0.01
Wind	Wind	$0.71	$0.71
Total		$2.64	$3.76

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 3-140 shows the markup component of average prices and of average monthly on peak and off peak prices using unadjusted cost-based offers. Table 3-141 shows the markup component of average prices and of average monthly on peak and off peak prices using adjusted cost-based offers. In the six months between April and September of 2025, when using unadjusted cost-based offers, $2.64 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. Using adjusted cost-based offers, $3.76 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the six months between April and September of 2025, the peak markup component was highest in July, $7.59 per MWh using unadjusted cost-based offers and $9.07 per MWh using adjusted cost-based offers. This corresponds to 8.6 percent and 10.2 percent of the day-ahead peak load weighted average LMP in July.

Table 3-140 Monthly markup components of day-ahead (Unadjusted) load-weighted LMP: April 2025 through September 2025

	2025		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Apr	$2.45	$3.01	$1.82
May	($0.44)	($1.07)	$0.19
Jun	$2.64	$4.06	$1.07
Jul	$4.10	$7.59	$0.19
Aug	$4.16	$5.53	$2.77
Sep	$1.71	$3.93	($0.66)
Total	$2.64	$4.16	$0.91

Table 3-141 Monthly markup components of day-ahead (Adjusted) load-weighted LMP: April 2025 through September 2025

	2025		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Apr	$3.30	$4.04	$2.48
May	$0.81	$0.10	$1.52
Jun	$3.75	$5.04	$2.33
Jul	$5.61	$9.07	$1.74
Aug	$5.29	$6.53	$4.02
Sep	$2.20	$4.03	$0.25
Total	$3.76	$5.14	$2.09

Markup Component of Day-Ahead Zonal Prices

Table 3-142 shows the markup component of annual average day-ahead price using unadjusted cost-based offers for each zone and for adjusted offers in Table 3-143.

The smallest zonal all hours average markup component using unadjusted cost-based offers for the six months between April and September of 2025 was in OVEC, $2.16 per MWh, while the highest was in PEPCO, $6.75 per MWh. The smallest zonal on peak average markup using unadjusted cost-based offers was in OVEC, $3.22 per MWh, while the highest was in PEPCO, $12.26 per MWh.

Table 3-142 Day-ahead average zonal markup component (Unadjusted): April through September, 2025

	2025 (Apr - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$5.01	$9.36	$0.77
AEP	$4.16	$6.74	$1.63
APS	$3.76	$5.97	$1.59
ATSI	$5.16	$8.60	$1.78
BGE	$4.47	$7.60	$1.42
COMED	$4.13	$4.58	$3.68
DAY	$3.60	$5.51	$1.73
DOM	$2.88	$4.06	$1.72
DPL	$3.35	$6.35	$0.44
DUKE	$3.47	$5.47	$1.52
DUQ	$4.03	$6.88	$1.26
EKPC	$3.99	$6.59	$1.45
JCPLC	$4.94	$9.39	$0.59
MEC	$2.51	$5.09	($0.01)
OVEC	$2.16	$3.22	$0.97
PE	$3.39	$5.61	$1.22
PECO	$5.56	$10.60	$0.66
PEPCO	$6.75	$12.26	$1.37
PPL	$4.22	$8.28	$0.25
PSEG	$4.01	$7.39	$0.70
REC	$4.25	$7.76	$0.85

Table 3-143 Day-ahead average zonal markup component (Adjusted): April through September, 2025

	2025 (Apr - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$6.22	$10.41	$2.12
AEP	$5.56	$7.84	$3.32
APS	$4.82	$6.65	$3.01
ATSI	$6.24	$9.50	$3.03
BGE	$5.55	$7.80	$3.34
COMED	$5.25	$5.82	$4.68
DAY	$4.87	$6.54	$3.23
DOM	$4.00	$4.93	$3.09
DPL	$4.79	$7.65	$1.98
DUKE	$4.62	$6.38	$2.89
DUQ	$5.07	$7.66	$2.53
EKPC	$5.31	$7.70	$2.94
JCPLC	$6.39	$10.77	$2.08
MEC	$3.95	$6.19	$1.74
OVEC	$3.74	$4.80	$2.57
PE	$4.75	$6.99	$2.53
PECO	$6.93	$11.90	$2.04
PEPCO	$7.48	$11.83	$3.21
PPL	$5.64	$9.56	$1.77
PSEG	$5.36	$8.63	$2.13
REC	$5.51	$8.77	$2.33

Markup by Day-Ahead Price Levels

Table 3-144 and Table 3-145 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 3-144 Day-ahead average markup component (By LMP category, unadjusted): April through September, 2025

	2025 (Apr - Sep)	
LMP Category	Markup Component	Frequency
$10 to $15	($1.42)	0.9%
$15 to $20	($0.28)	8.1%
$20 to $25	($0.45)	13.4%
$25 to $50	$1.06	52.5%
$50 to $75	$5.39	16.4%
$75 to $100	$6.98	5.2%
$100 to $125	$12.22	1.6%
$125 to $150	$11.64	0.5%
>= $150	$13.48	1.3%

Table 3-145 Day-ahead average markup component (By LMP category, adjusted): April through September, 2025

	2025 (Apr - Sep)	
LMP Category	Markup Component	Frequency
$10 to $15	($0.45)	0.9%
$15 to $20	$0.68	8.1%
$20 to $25	$0.65	13.4%
$25 to $50	$2.37	52.5%
$50 to $75	$5.95	16.4%
$75 to $100	$7.87	5.2%
$100 to $125	$13.03	1.6%
$125 to $150	$12.55	0.5%
>= $150	$14.77	1.3%

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:[216]

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

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

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

demand. For example, research estimates find short run electricity demand elasticity ranging from -0.2 to -0.4.[217] 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:[218]

$$\frac{HHI}{\varepsilon} = \frac{0.1}{0.2} = \frac{P - MC}{P} = 0.5$$

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 $50.61 per MWh and an average HHI of 686 in the first nine months of 2025, average PJM prices would theoretically range from $61 to $77 per MWh, an implied markup of 17.2 to 34.3 percent, using the elasticity range of -0.2 to -0.4. Given the elasticity estimates, the theoretical prices exceed marginal costs because the exercise of market power is profit maximizing. In the PJM market, market power mitigation limits the exercise of market power, so prices cannot reach the higher theoretical level. Actual prices, averaging $50.51 per MWh with markups at -0.2 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.

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 3-146 categorizes day-ahead and real-time marginal unit intervals by markup level and TPS test status. In the first nine months of 2025, 3.0 percent of real-time marginal unit intervals and 3.3 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.

217 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>.

218 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.

Table 3-146 Percent of real-time marginal unit intervals with markup and local market power: January through September, 2025

	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	40.1%	3.1%	43.3%	52.7%	6.2%	58.9%
Zero Markup	21.6%	5.8%	27.4%	17.7%	7.3%	25.0%
$0 to $5	11.6%	1.1%	12.6%	7.4%	1.4%	8.9%
$5 to $10	4.3%	0.7%	5.0%	2.6%	0.4%	3.0%
$10 to $15	2.1%	0.6%	2.7%	1.2%	0.3%	1.5%
$15 to $20	1.1%	0.3%	1.3%	0.4%	0.3%	0.7%
$20 to $25	0.7%	0.1%	0.8%	0.2%	0.1%	0.3%
$25 to $50	3.3%	0.3%	3.6%	0.7%	0.4%	1.0%
$50 to $75	1.4%	0.1%	1.5%	0.2%	0.1%	0.3%
$75 to $100	1.1%	0.1%	1.2%	0.1%	0.0%	0.2%
Above $100	0.5%	0.0%	0.6%	0.1%	0.1%	0.2%
Total Positive Markup	26.1%	3.3%	29.3%	13.0%	3.0%	16.1%
Total	87.9%	12.1%	100.0%	83.5%	16.5%	100.0%

The markup of marginal units was zero or negative in 83.9 percent of real-time marginal unit intervals and 70.7 percent of day-ahead marginal unit intervals in the first nine months of 2025. 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 2025. The 26.1 percent of day-ahead marginal units and 13.0 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.