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 2024.

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 49.5 percent of the days in 2024. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM aggregate energy market in 2024 was, on average, unconcentrated by FERC HHI standards. The average HHI was 714 with a minimum of 553 and a maximum of 983. The baseload segment of the supply curve was unconcentrated. The intermediate segment of the supply curve was moderately concentrated 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.

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- 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).

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Overview

Supply and Demand

Market Structure

- **Supply.** In 2024, 3,206 MW of new resources were added in the energy market, and 527 MW of resources were retired.
- The real-time hourly on peak average offered supply in 2024 increased by 2.8 percent, from 2023, from 137,865 MWh to 141,742 MWh.
- The day-ahead hourly average offered supply in 2024 decreased by 0.2 percent, from 2023, from 149,346 MWh to 149,120 MWh.
- The real-time hourly average cleared generation in 2024 increased by 2.5 percent from 2023, from 92,457 MWh to 94,814 MWh.
- The day-ahead hourly average cleared supply in 2024, including INCs and UTCs, decreased by 5.3 percent from 2023 from 116,042 MWh to 109,932 MWh.
- **Demand.** The real-time hourly peak load plus exports in 2024 was 154,045 MWh (148,218 MWh of load plus 5,827 MWh of gross exports) in the HE 1700 (EPT) on July 15, 2024, which was 0.8 percent, 1,248 MWh, higher than the PJM peak load plus exports in 2023, which was 152,797 MWh in the HE 1800 (EPT) on July 27, 2023.
- The real-time hourly peak load without exports in 2024 was 148,890 MWh in the HE 1800 (EPT) on July 16, 2024, higher than the PJM peak load in 2023, which was 144,215 MWh in the HE 1800 (EPT) on July 27, 2023.
- The real-time hourly average load in 2024 increased by 3.6 percent from 2023, from 86,193 MWh to 89,274 MWh.
- The day-ahead hourly average cleared demand in 2024, including DECs and UTCs, decreased by 6.5 percent from 2023, from 113,807 MWh to 106,355 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 21.0 percent and the cleared increment MW increased by 12.8 percent in 2024 compared to 2023. The hourly average submitted decrement bid MW increased by 25.2 percent and the cleared decrement MW increased by 11.5 percent in 2024 compared to 2023. The hourly average submitted up to congestion bid MW decreased by 54.9 percent and the cleared up to congestion bid MW decreased by 46.0 percent in 2024 compared to 2023.

Market Performance

- **Generation Fuel Mix.** In 2024, generation from coal units increased 1.4 percent, generation from natural gas units increased 3.5 percent, generation from oil units increased 53.1 percent, generation from wind units increased 8.5 percent, and generation from solar units increased 58.1 percent compared to 2023.
- **Fuel Diversity.** The fuel diversity of energy generation in 2024, measured by the fuel diversity index for energy (FDI_e), increased 0.8 percent compared to 2023.
- **Marginal Resources.** In the PJM Real-Time Energy Market in 2024, coal units were 13.5 percent and natural gas units were 73.7 percent of marginal resources. In 2023, coal units were 5.5 percent and natural gas units were 83.1 percent of marginal resources.
- **Prices.** The real-time load-weighted average LMP in 2024 increased $2.66 per MWh, or 8.5 percent from 2023, from $31.08 per MWh to $33.74 per MWh.
- The day-ahead load-weighted average LMP for 2024 increased $1.86 or 5.8 percent from 2023, from $31.93 per MWh to $33.79 per MWh.
- **Fast Start Pricing.** The real-time load-weighted average PLMP was $33.74 per MWh in 2024, which is 7.7 percent, $2.43 per MWh, higher than the real-time load-weighted average DLMP of $31.31 per MWh.
- The day-ahead load-weighted average PLMP was $33.79 per MWh in 2024, which is 0.2 percent, $0.07 per MWh, higher than the day-ahead load-weighted average DLMP of $33.72 per MWh.

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- **Components of Real-Time LMP.** In the PJM Real-Time Energy Market in 2024, 12.1 percent of the real-time load-weighted LMP was the result of coal costs, 39.7 percent was the result of gas costs, 6.0 percent was the result of the cost of emission allowances, 8.9 percent was the result of transmission constraint violation penalty factors, and 1.7 percent was the result of the use of fast start pricing.
- **Changes in Real-Time LMP.** Of the $2.66 per MWh increase in the real-time load-weighted average LMP, $0.50 per MWh (18.9 percent) was the fuel and consumables cost components of LMP, -$0.05 per MWh (-1.9 percent) was the emissions cost components of LMP, 0.16 per MWh (6.2 percent) was the sum of the markup, maintenance, and ten percent adder components of LMP, $1.39 per MWh (52.4 percent) was the transmission constraint penalty factor component of LMP, and $0.10 per MWh (3.7 percent) was the scarcity component of LMP.
- **Price Convergence.** Hourly and daily price differences between the day-ahead and real-time energy markets fluctuate continuously and substantially from positive to negative. The average difference between day-ahead and real-time average prices was -$0.09 per MWh in 2024, and -$0.69 per MWh in 2023. 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 39 intervals with five minute shortage pricing on 17 days in 2024. These shortages did not correspond with any emergency warning or action. Four of the 39 intervals of shortage did correspond with two synchronized reserve events. Nine of the 39 intervals of shortage did correspond with cold weather alerts. One of the 39 intervals of shortage did correspond with a hot weather alert.
- **SCED Shortage Intervals.** There were 6,811 five minute intervals, or 6.5 percent of all five minute intervals, in 2024 for which at least one RT SCED solution showed a shortage of reserves, and 1,905 five minute intervals, or 1.8 percent of all five minute intervals, in 2024 for which more than one RT SCED solution showed a shortage of reserves. PJM triggered shortage pricing for 39 five minute intervals, or 0.6 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 181 days, 49.5 percent of the days, in 2024 and 179 days, 49.0 percent of the days, in 2023.
- **Local Market Power.** In 2024, in the real-time market, the 500 kV system, nine zones, and the PJM/MISO interface experienced congestion resulting from one or more constraints binding for 100 or more hours. For seven out of the top 10 congested facilities (by real-time binding hours) in 2024, 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 1.7 percent in 2023 to 1.2 percent in 2024. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 1.3 percent in 2023 to 1.5 percent in 2024. 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.

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The analysis of the application of the TPS test to local markets demonstrates that it is working to identify pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, including for reactive support. In the day-ahead energy market, for units committed for reliability reasons, offer-capped unit hours increased from 0.13 percent 2023 to 0.21 percent in 2024. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.14 percent in 2023 to 0.08 percent in 2024. 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 as if they have market power.

- **Parameter Mitigation.** In 2024, 27.7 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, 34.4 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 2024, no units qualified for an FMU adder. In 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 -0.01 when using unadjusted cost-based offers in 2024, some marginal units did have substantial markups. The highest markup for any marginal unit in the real-time market in 2024 was more than $900 per MWh, using unadjusted cost-based offers.

  While the average markup index in the day-ahead market was $0.08 per MWh in 2024, some marginal units did have substantial markups. The highest markup for any marginal unit in the day-ahead market in 2024 was more than $200 per MWh and the highest markup in 2023 was more than $250 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 2024, the unadjusted markup component (net of positive and negative markup components) of LMP was -$0.01 per MWh or -0.1 percent of the PJM load-weighted average LMP. July had the highest unadjusted peak markup component, $6.10 per MWh, or 10.0 percent of the real-time 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 3.4 percent of all real-time marginal unit intervals in 2024, 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 2024, 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 88 days. 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 run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy. (Priority: Low. First reported 2020. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy. (Priority: Medium. First reported 2020. Status: Not adopted.)

Cost-Based Offers

- The MMU recommends that Manual 15 (Cost Development Guidelines) be replaced or updated with a straightforward description of the components of cost-based offers and the mathematically correct calculation of cost-based offers for thermal resources. (Priority: Medium. First reported 2016. Status: Adopted 2023.)
- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Adopted 2022.)
- The MMU recommends the removal of all maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics. (Priority: Medium. First reported 2020. Status: Adopted 2023.)
- The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of the operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. (Priority: Medium. First reported 2020. Status: 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

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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.)[7]
- 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 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

7 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.

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with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)[8]

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 intermittent 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: Adopted 2023.)
- 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.)

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.)[9]
- 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.)

8 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.

9 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.

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- 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.)
- The MMU recommends, if the capacity market seller offer cap were to be calculated using the historical average balancing ratio, that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs), and only include those events that trigger emergencies at a defined zonal or higher level. (Priority: Medium. First reported 2018. Status: Adopted, 2023.[10])

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.)
- 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

10 See 184 FERC ¶ 61,058 (2023).

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.

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>.

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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.)
- 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.

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Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in 2024, 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 2024, LMP increased by $2.66 per MWh compared to 2023. The fuel cost components of LMP (the sum of gas, coal, oil, landfill gas, and consumables) increased $0.50 per MWh, 18.9 percent of the increase in LMP. The emissions cost components of LMP, including opportunity costs for emissions limited resources, decreased by $0.05 per MWh, -1.9 percent of the increase in LMP. The transmission constraint penalty factor component increased by $1.39 per MWh, 52.4 percent of the increase in LMP, primarily as a result of PJM actions to reduce the line limits applied in SCED.

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 2024 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 2024, the sum of the markup, ten percent adder, and maintenance cost (not short run marginal cost) components increased by $0.16 per MWh or 6.2 percent of the increase in LMP.

The potential for prolonged and excessively high administrative pricing in the energy market due to reserve penalty factors and transmission constraint penalty factors remains an issue that needs to be addressed.[17] There also continue to be significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on accurately estimated reserve levels. For example, PJM approved 2.5 percent of solved shortage cases in January 2024, but only 0.6 percent for the year. Six other 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. As directed by FERC Order 825, PJM should approve shortage cases based on the 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, transmission penalty factors, load forecast bias, and hydro resource schedules change the dispatch of the system, affect prices, and can create significant price increases, particularly through transmission 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. Violations of the artificially reduced control limits on constraint line ratings were the largest single component of the increase in LMP in 2024. In 2024, the control limit used

17 177 FERC ¶ 61,209 (2021).

18 155 FERC ¶ 61,276 (2016).

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in RT SCED for 94 percent of violated transmission constraint intervals was less than 100 percent, 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 penalty factor's contribution to the load-weighted average LMP in 2024 would have decreased by 99.4 percent from $3.01 to $0.02 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 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 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 three 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.

PJM's arguments for changing energy market price formation asserted that fast start pricing and PJM's rejected extended ORDC would price flexibility in the market, but instead they benefit inflexible units. The fast start pricing and extended ORDC solutions undercut LMP logic rather than directly addressing the underlying issues. The solution is not to accept that the inflexible CT should be paid or set price based on its commitment costs rather than its short run marginal costs. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? Are units inflexible because the PJM software does not model combined cycle transitions? The question of how to provide market incentives for investment in flexible units, for investment in increased flexibility of existing units, and for operating at the full extent of existing flexibility should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying excess uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

The relationship between supply and demand, regardless of the specific market, along with market concentration and the extent of pivotal suppliers, is referred to as the supply-demand fundamentals, or economic fundamentals, or market structure. The market structure of the PJM aggregate energy market is partially competitive because aggregate market power does exist for a significant number of hours. The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. It is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. Even a low HHI may be consistent with the exercise of market power with a low price elasticity of demand. The current market power mitigation rules for the PJM energy market rely on the assumption that the ownership structure of the aggregate market ensures competitive outcomes. This assumption

19 See 173 FERC ¶ 61,244 (2020).

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requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market at times. High markups for some units demonstrate the potential to exercise market power both routinely and during high demand conditions. The existing market power mitigation measures do not address aggregate market power. The MMU is developing an aggregate market power test and will propose market power mitigation rules to address aggregate market power.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[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] PJM continued to ignore the evidence cited by the Commission and denies the prevalence of these issues, instead of ensuring that market power mitigation works as intended and results in efficient market outcomes.[23] Many of these issues can be resolved by simple rule changes. The MMU proposed these rule changes in its response submitted on October 15, 2021, and in the stakeholder process.[24] [25] The MMU recommendations would shorten the solution time of the day-ahead market software, which would help facilitate enhanced combined cycle modelling. The proposal that PJM filed with FERC on March 1, 2024, would have weakened market power mitigation as part of implementing the enhanced combined cycle modelling project, although PJM failed to explain why such weakening makes sense. PJM's proposal would have ensured that the identified issues with the implementation of market power mitigation in the energy market would never have been addressed and would have been exacerbated. On April 30, 2024, FERC rejected PJM's proposal because "PJM's proposal would create the ability for Market Sellers to exercise market power, which the Commission has found unjust and unreasonable."[26] 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. 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. 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, modified to correct the cost offer selection issue, 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

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).
23 See Answer of PJM Interconnection L.L.C., Docket No. EL21-78-000 (September 15, 2021).
24 *See* "Comments of the Independent Market Monitor for PJM," Docket No. EL21-78 (October 15, 2021).
25 *See* "Schedule Selection Proposal," MMU presentation to the Markets and Reliability Committee (October 25, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MRC_Schedule_Selection_20231025.pdf>; "Schedule Selection: IMM Package," MMU Presentation to the Market Implementation Committee (September 6, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Schedule_Selection_IMM_Package_20230906.pdf>; "Schedule Selection: IMM Proposal," MMU Presentation to the Market Implementation Committee (August 9, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Schedule_Selection_IMM_Proposal_20230809.pdf>; "Least Cost Schedule Analysis," MMU Presentation at the MIC Special Session (July 17, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Special_Session_Least_Cost_Schedule_Analysis_20230717.pdf>; "Multischedule Model and Mitigation: IMM Package," MMU Presentation to the MIC Special Session (May 24, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Multischedule_Model_and_Mitigation_IMM_Package_20230524.pdf>; "Education: Schedule Selection and Market Power Mitigation," MMU Presentation to the MIC Special Session (March 29, 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Special_Session_Education_Schedule_%20Selection_and_Market_Power_Mitigation_20230330.pdf>; "Offer Schedule Selection," MMU Presentation to the Market Implementation Committee (February 8 2023), <https://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Offer_Schedule_Selection_20230208.pdf>.

26 187 FERC 61,051 at P 25 (2024).

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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 2024 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. The MMU concludes that the PJM energy market results were competitive in 2024.

Supply and Demand

Market Structure

Supply

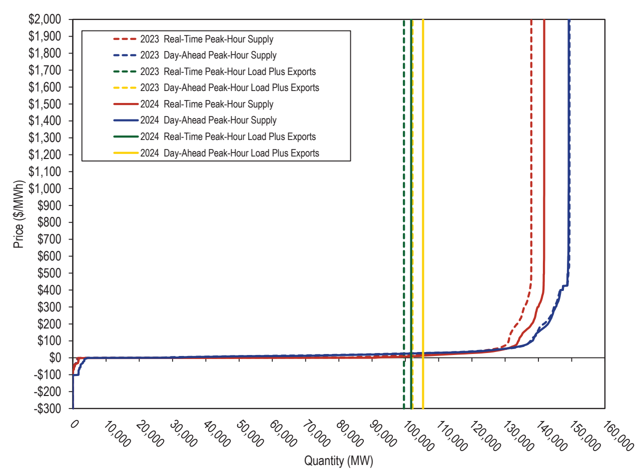
Supply includes physical generation, imports and virtual transactions.

In 2024, 3,206 MW of new resources were added in the energy market, and 527 MW of resources were retired.

Figure 3-1 shows real-time and day-ahead hourly supply curves for 2023 and 2024.[27] 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 for 2024 increased 2.8 percent from 2023, from 137,865 MWh to 141,742 MWh. The day-ahead hourly average offered supply for 2024 decreased 0.2 percent from 2023, from 149,346 MWh to 149,120 MWh.

Figure 3-1 Real-time and day-ahead hourly supply curves: 2023 and 2024



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

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Figure 3-2 shows the typical dispatch range.

Figure 3-2 Typical dispatch range of supply curves

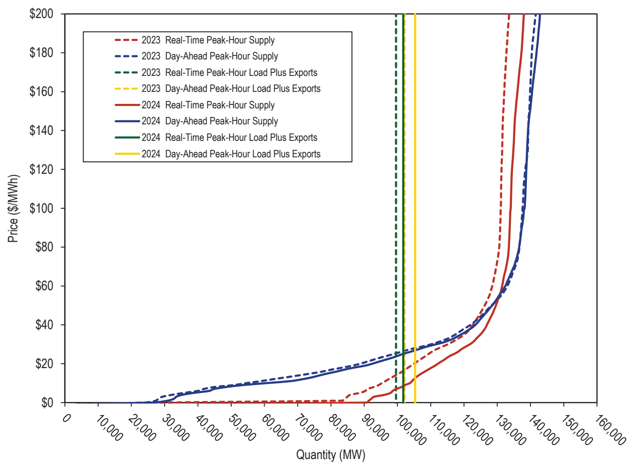


Table 3-2 shows the price elasticity of the real-time supply curve for the peak hours for 2023 and 2024 by load level.

The supply curve in 2024 was most elastic in the 95 to 115 GW range at 0.087, which was less elastic than the supply curve in the 95 to 115 GW range in 2023, with an elasticity of 0.129.

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

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

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

Table 3-2 Price elasticity of the supply curve

	GW				
	Min - 75	75 - 95	95 - 115	115 - 135	135 - Max
2020	0.015	0.174	0.327	0.021	0.001
2021	-	0.015	0.258	0.030	0.004
2022	-	0.008	0.172	0.043	0.010
2023	-	0.015	0.129	0.005	-
2024	-	0.015	0.087	0.016	0.002

Real-Time Supply

The real-time hourly average cleared generation in 2024 increased by 2.5 percent from 2023, from 92,457 MWh to 94,814 MWh.[28]

The real-time hourly average cleared supply including imports in 2024 increased by 2.6 percent from 2023, from 94,165 MWh to 96,605 MWh.

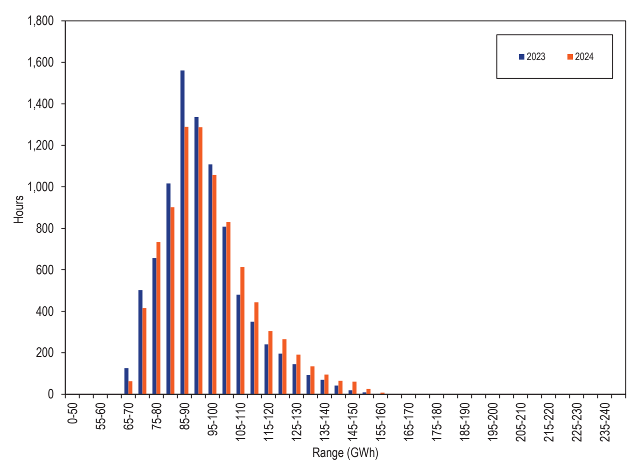
In the PJM Real-Time Energy Market, there are three types of supply offers:

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

PJM Real-Time Supply Frequency

Figure 3-3 shows the hourly distribution of the real-time generation plus imports for 2023 and 2024.

Figure 3-3 Distribution of real-time generation plus imports: 2023 and 2024[29]



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

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

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PJM Real-Time Average Cleared Supply

Table 3-3 shows the real-time hourly average cleared supply and its standard deviation for 2001 through 2024.

The real-time hourly average cleared generation in 2024 increased by 2.5 percent from 2023, from 92,457 MWh to 94,814 MWh. It was the highest annual real-time hourly average cleared generation since the start of PJM markets.

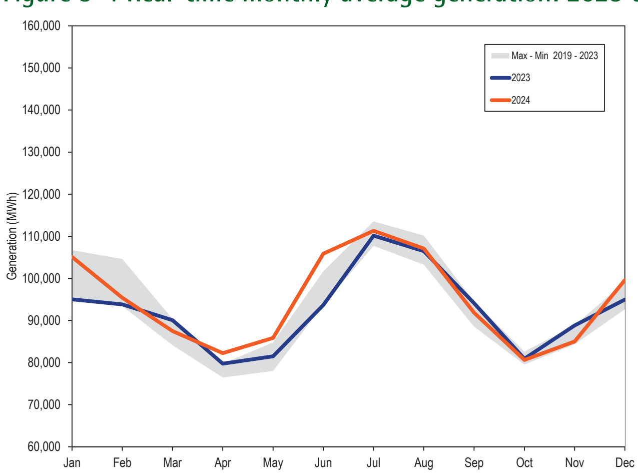
Table 3-3 Real-time hourly average generation and generation plus imports: 2001 through 2024

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2001	29,553	4,937	32,552	5,285	NA	NA	NA	NA
2002	34,928	7,535	38,535	7,751	18.2%	52.6%	18.4%	46.7%
2003	36,628	6,165	40,205	6,162	4.9%	(18.2%)	4.3%	(20.5%)
2004	51,068	13,790	55,781	14,652	39.4%	123.7%	38.7%	137.8%
2005	81,127	15,452	86,353	15,981	58.9%	12.0%	54.8%	9.1%
2006	82,780	13,709	86,978	14,402	2.0%	(11.3%)	0.7%	(9.9%)
2007	85,860	14,018	90,351	14,763	3.7%	2.3%	3.9%	2.5%
2008	83,476	13,787	88,899	14,256	(2.8%)	(1.7%)	(1.6%)	(3.4%)
2009	78,026	13,647	83,058	14,140	(6.5%)	(1.0%)	(6.6%)	(0.8%)
2010	82,585	15,556	87,386	16,227	5.8%	14.0%	5.2%	14.8%
2011	85,775	15,932	90,511	16,759	3.9%	2.4%	3.6%	3.3%
2012	88,708	15,701	94,083	16,505	3.4%	(1.4%)	3.9%	(1.5%)
2013	89,769	15,012	94,833	15,878	1.2%	(4.4%)	0.8%	(3.8%)
2014	90,894	15,151	96,295	16,199	1.3%	0.9%	1.5%	2.0%
2015	88,628	16,118	94,330	17,313	(2.5%)	6.4%	(2.0%)	6.9%
2016	91,304	17,731	95,054	17,980	3.0%	10.0%	0.8%	3.9%
2017	90,945	15,194	92,721	15,493	(0.4%)	(14.3%)	(2.5%)	(13.8%)
2018	94,236	16,326	96,109	16,595	3.6%	7.5%	3.7%	7.1%
2019	93,434	16,357	94,618	16,515	(0.9%)	0.2%	(1.6%)	(0.5%)
2020	90,938	16,527	91,674	16,627	(2.7%)	1.0%	(3.1%)	0.7%
2021	93,644	16,786	94,501	16,884	3.0%	1.6%	3.1%	1.5%
2022	94,368	16,258	96,147	16,487	0.8%	(3.1%)	1.7%	(2.4%)
2023	92,457	14,683	94,165	14,668	(2.0%)	(9.7%)	(2.1%)	(11.0%)
2024	94,814	15,971	96,605	16,186	2.5%	8.8%	2.6%	10.3%

PJM Real-Time Monthly Average Generation

Figure 3-4 compares the real-time monthly average generation in 2023 and 2024 with the historic five-year range. The real-time monthly average generation in April, May, June and December 2024 was higher than the maximum monthly average generation for the past five years.

Figure 3-4 Real-time monthly average generation: 2023 through 2024



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Day-Ahead Cleared Supply

The day-ahead hourly average cleared supply in 2024, including INCs and UTCs, decreased by 5.3 percent from 2023 from 116,042 MWh to 109,932 MWh.

The day-ahead hourly average cleared supply in 2024, including INCs, UTCs and imports, decreased by 5.3 percent from 2023, from 116,411 MWh to 110,289 MWh.

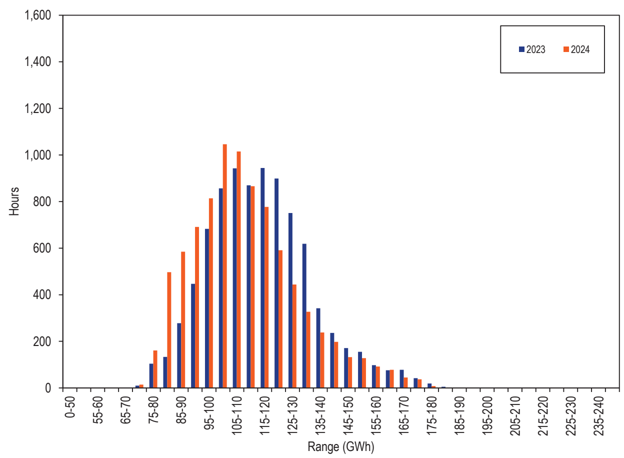
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MW, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MW and corresponding offer prices from a unit.
- **Increment Offer (INC).** Financial offer to supply MW and corresponding offer prices. INCs can be submitted by any market participant.
- **Up to Congestion Transaction (UTC).** Conditional transaction that permits a market participant to specify a maximum price spread for a specific amount of MW between the transaction source and sink. An up to congestion transaction is a matched pair of an injection and a withdrawal.
- **Import.** An import is an external energy transaction for a specific MW amount scheduled to PJM from another balancing authority. An import must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An import energy transaction that clears the day-ahead energy market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an import energy transaction approved in the day-ahead energy market will not physically flow in real time unless it is also submitted through the real-time energy market scheduling process.

PJM Day-Ahead Supply Duration

Figure 3-5 shows the distribution of the day-ahead hourly cleared supply, including increment offers, up to congestion transactions, and imports for 2023 and 2024.

Figure 3-5 Distribution of day-ahead cleared supply plus imports: 2023 and 2024[30]



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

PJM Day-Ahead Average Supply

Table 3-4 presents day-ahead hourly cleared supply summary statistics for each year for 2001 through 2024.

The day-ahead hourly average cleared supply in 2024, including INCs and UTCs, decreased by 5.3 percent from 2023 from 116,042 MWh to 109,932 MWh. The decrease was primarily a result of decreased UTC volumes.

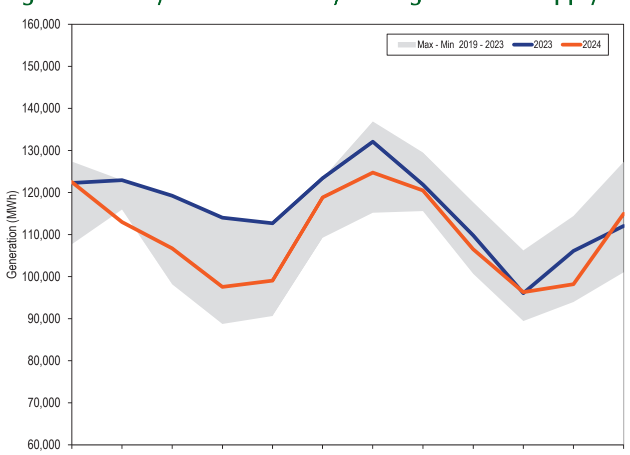
Table 3-4 Day-ahead hourly average cleared supply and cleared supply plus imports: 2001 through 2024

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2001	26,762	4,595	27,497	4,664	NA	NA	NA	NA
2002	31,434	10,007	31,982	10,015	17.5%	117.8%	16.3%	114.7%
2003	40,642	8,292	41,183	8,287	29.3%	(17.1%)	28.8%	(17.3%)
2004	62,755	17,141	63,654	17,362	54.4%	106.7%	54.6%	109.5%
2005	94,438	17,204	96,449	17,462	50.5%	0.4%	51.5%	0.6%
2006	100,056	16,543	102,164	16,559	5.9%	(3.8%)	5.9%	(5.2%)
2007	108,707	16,549	111,023	16,729	8.6%	0.0%	8.7%	1.0%
2008	105,485	15,994	107,885	16,136	(3.0%)	(3.4%)	(2.8%)	(3.5%)
2009	97,388	16,364	100,022	16,397	(7.7%)	2.3%	(7.3%)	1.6%
2010	107,307	21,655	110,026	21,837	10.2%	32.3%	10.0%	33.2%
2011	117,130	20,977	119,501	21,259	9.2%	(3.1%)	8.6%	(2.6%)
2012	134,479	17,905	136,903	18,080	14.8%	(14.6%)	14.6%	(15.0%)
2013	148,323	18,783	150,595	18,978	10.3%	4.9%	10.0%	5.0%
2014	146,672	33,145	148,906	33,346	(1.1%)	76.5%	(1.1%)	75.7%
2015	114,890	19,165	117,147	19,406	(21.7%)	(42.2%)	(21.3%)	(41.8%)
2016	131,618	22,329	133,246	22,368	14.6%	16.5%	13.7%	15.3%
2017	130,603	20,035	131,142	20,153	(0.8%)	(10.3%)	(1.6%)	(9.9%)
2018	114,556	20,239	114,967	20,224	(12.3%)	1.0%	(12.3%)	0.4%
2019	117,250	18,909	117,622	18,881	2.4%	(6.6%)	2.3%	(6.6%)
2020	111,470	19,749	111,636	19,729	(4.9%)	4.4%	(5.1%)	4.5%
2021	102,431	18,823	102,599	18,850	(8.1%)	(4.7%)	(8.1%)	(4.5%)
2022	111,044	18,810	111,353	18,901	8.4%	(0.1%)	8.5%	0.3%
2023	116,015	18,561	116,384	18,574	4.5%	(1.3%)	4.5%	(1.7%)
2024	109,932	19,167	110,289	19,209	(5.2%)	3.3%	(5.2%)	3.4%

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 2023 and 2024 with the historic five-year range. The monthly average day-ahead cleared supply from February of 2024 was lower than the minimum of the past five years, primarily as a result of decreased UTC volumes.

Figure 3-6 Day-ahead monthly average cleared supply: 2023 through 2024



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Real-Time and Day-Ahead Supply

Table 3-5 presents summary statistics for day-ahead and real-time cleared supply in 2023 and 2024. 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 2024 increased 161 MWh from 2023, from -798 MWh to -637 MWh. The total day-ahead average supply less the total real-time average supply in 2024 decreased 8,563 MWh from 2023, from 22,247 MWh to 13,684 MWh.

Table 3-5 Day-ahead and real-time hourly cleared supply (MWh): 2023 and 2024

		Day Ahead					Real Time		Day Ahead Less Real Time	
		Generation	INC Offers	Up to Congestion	Imports	Total Supply	Generation	Total Supply	Generation	Supply
Average	2023	91,659	4,419	19,964	369	116,411	92,457	94,165	(798)	22,247
	2024	94,177	4,982	10,774	357	110,289	94,814	96,605	(637)	13,684
Median	2023	89,077	4,277	19,578	300	115,235	90,322	91,934	(1,245)	23,301
	2024	91,078	4,881	10,435	303	107,847	92,175	93,768	(1,097)	14,079
Standard Deviation	2023	15,678	1,553	8,463	322	18,565	14,683	14,668	995	3,897
	2024	16,973	1,654	4,138	312	19,209	15,971	16,186	1,002	3,023
Peak Average	2023	99,136	5,193	21,991	418	126,739	99,536	101,427	(400)	25,312
	2024	101,612	5,715	12,602	427	120,355	101,649	103,696	(36)	16,659
Peak Median	2023	95,994	5,124	21,543	356	124,973	96,607	98,541	(613)	26,432
	2024	97,677	5,688	12,250	360	116,977	98,052	99,819	(375)	17,157
Peak Standard Deviation	2023	15,159	1,507	8,279	351	16,258	14,099	13,952	1,060	2,306
	2024	16,432	1,528	3,864	346	16,942	15,504	15,669	928	1,273
Off-Peak Average	2023	85,189	3,748	18,209	327	107,473	86,331	87,879	(1,143)	19,594
	2024	87,680	4,341	9,176	295	101,493	88,842	90,410	(1,162)	11,084
Off-Peak Median	2023	83,634	3,616	17,440	254	105,738	84,994	86,486	(1,360)	19,252
	2024	85,051	4,223	8,568	250	98,597	86,597	88,123	(1,546)	10,474
Off-Peak Standard Deviation	2023	13,017	1,250	8,226	288	15,558	12,217	12,156	800	3,402
	2024	14,608	1,485	3,684	265	16,574	13,838	13,931	770	2,643

Figure 3-7 shows the average cleared volumes of day-ahead and real-time supply by hour of the day for 2024. 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): 2024

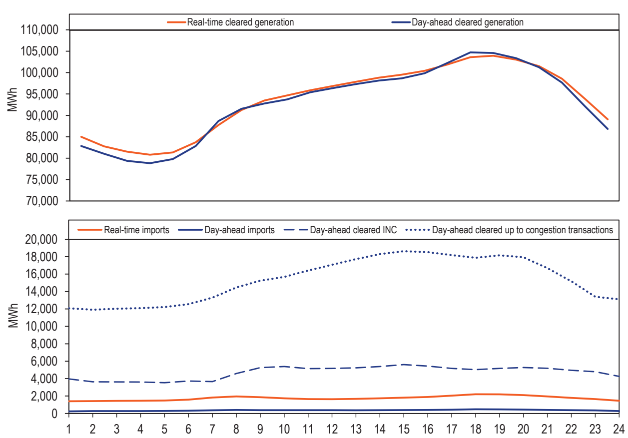
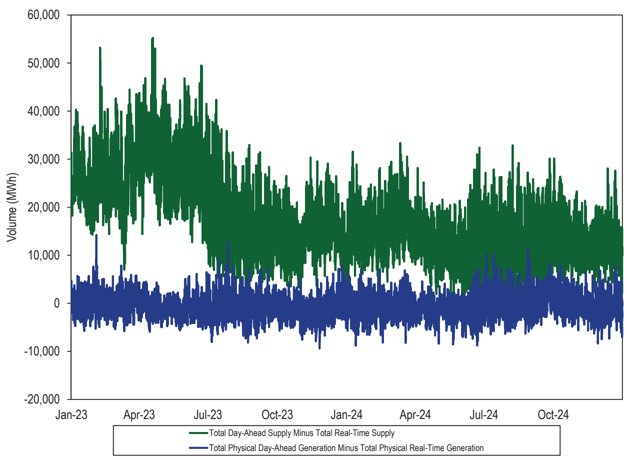


Figure 3-8 shows the difference between day-ahead and real-time daily average cleared supply in 2023 and 2024. The blue line is the total physical day-ahead generation less the total physical real-time generation, and the green line is the total day-ahead cleared supply less the total real-time cleared 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: 2023 through 2024



Demand

Demand includes physical load and exports and virtual demand 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.[31]

Table 3-6 shows the peak load without exports for 2009 through 2024.

The real-time hourly peak load without exports in 2024 was 148,890 MWh in the HE 1800 (EPT) on July 16, 2024, higher than the PJM peak load in 2023, which was 144,215 MWh in the HE 1800 (EPT) on July 27, 2023.

31 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 Actual PJM peak load without exports: 2009 through 2024[32 33]

	Date	Hour Ending (EPT)	PJM Load (MWh)	Annual Change (MWh)	Annual Change (%)
2009	Mon, August 10	17	123,900	NA	NA
2010	Tue, July 06	17	133,297	9,397	7.6%
2011	Thu, July 21	17	154,095	20,798	15.6%
2012	Tue, July 17	17	150,879	(3,216)	(2.1%)
2013	Thu, July 18	17	153,790	2,911	1.9%
2014	Tue, June 17	18	138,448	(15,341)	(10.0%)
2015	Tue, July 28	17	140,266	1,818	1.3%
2016	Thu, August 11	16	148,577	8,311	5.9%
2017	Wed, July 19	18	142,387	(6,190)	(4.2%)
2018	Tue, August 28	17	147,042	4,656	3.3%
2019	Fri, July 19	18	148,228	1,185	0.8%
2020	Mon, July 20	17	141,449	(6,778)	(4.6%)
2021	Tue, August 24	17	145,563	4,114	2.9%
2022	Wed, July 20	18	144,356	(1,208)	(0.8%)
2023	Thu, July 27	18	144,215	(141)	(0.1%)
2024	Tue, July 16	18	148,890	4,675	3.2%

Table 3-7 shows the peak load plus exports from 2009 through 2024.

The real-time hourly peak load plus exports in 2024 was 154,045 MWh (148,218 MWh of load plus 5,827 MWh of gross exports) in the HE 1700 (EPT) on July 15, 2024, which was 0.8 percent, 1,248 MWh, higher than the PJM peak load plus exports in 2023, which was 152,797 MWh in the HE 1800 (EPT) on July 27, 2023.

Table 3-7 Actual PJM peak load plus export: 2009 through 2024[34 35]

	Date	Hour Ending (EPT)	PJM Load Plus Export (MWh)	Annual Change (MWh)	Annual Change (%)
2009	Mon, August 10	16	135,923	NA	NA
2010	Wed, July 07	17	149,376	13,453	9.9%
2011	Thu, July 21	17	169,290	19,915	13.3%
2012	Tue, July 17	18	166,081	(3,210)	(1.9%)
2013	Thu, July 18	17	157,277	(8,804)	(5.3%)
2014	Tue, June 17	18	142,428	(14,850)	(9.4%)
2015	Fri, February 20	8	144,850	2,422	1.7%
2016	Thu, August 11	17	154,743	9,893	6.8%
2017	Thu, July 20	16	148,343	(6,400)	(4.1%)
2018	Tue, August 28	17	152,509	4,166	2.8%
2019	Fri, July 19	18	153,589	1,080	0.7%
2020	Mon, July 20	18	148,996	(4,593)	(3.0%)
2021	Tue, August 24	18	151,680	2,684	1.8%
2022	Wed, July 20	18	149,531	(2,150)	(1.4%)
2023	Thu, July 27	18	152,797	3,267	2.2%
2024	Mon, July 15	17	154,045	1,248	0.8%

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

33 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.

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

35 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.

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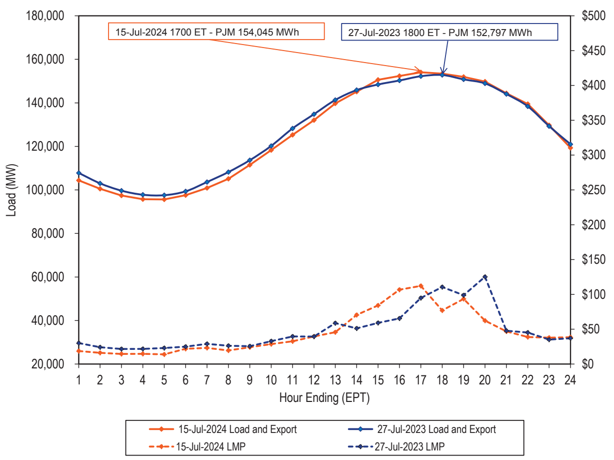
Figure 3-9 compares prices and demand on the peak load days in 2023 and 2024. The real-time average LMP for July 27, 2023, peak load hour was $110.52 per MWh, and for July 15, 2024, peak load hour it was $112.22 per MWh.

Figure 3-9 Peak load and export day comparison



Real-Time Demand

The real-time hourly average load in 2024 increased by 3.6 percent from 2023, from 86,193 MWh to 89,274 MWh.[36]

The real-time hourly average demand including exports in 2024 increased by 2.5 percent from 2023, from 92,455 MWh to 94,787 MWh.

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

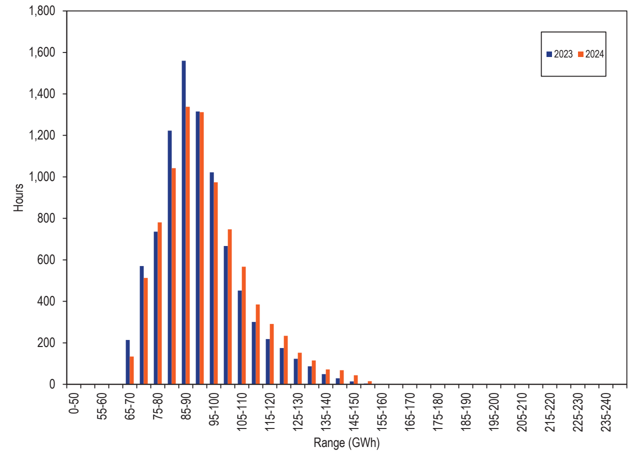
- **Load.** The actual MWh level of energy used by load within PJM.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. A real-time export must have a valid OASIS reservation when offered, must have available ramp room to support the export, must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

36 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 in 2023 and 2024.[37]

Figure 3-10 Distribution of real-time load plus exports: 2023 and 2024[38]



PJM Real-Time Average Load

Table 3-8 presents real-time hourly demand summary statistics for 2001 through 2024.[39]

The real-time hourly average load in 2024 increased by 3.6 percent from 2023, from 86,193 MWh to 89,274 MWh. It was the second highest annual real-time hourly average load since the start of PJM markets. Including exports, it was the highest annual real-time hourly average demand since the start of PJM markets.

37 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>.

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

39 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.

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Table 3-8 Real-time hourly average load and load plus exports: 2001 through 2024

	PJM Real-Time Demand (MWh)				Year to Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
2001	30,297	5,873	32,165	5,564	NA	NA	NA	NA
2002	35,776	7,976	37,676	8,145	18.1%	35.8%	17.1%	46.4%
2003	37,395	6,834	39,380	6,716	4.5%	(14.3%)	4.5%	(17.5%)
2004	49,963	13,004	54,953	14,947	33.6%	90.3%	39.5%	122.6%
2005	78,150	16,296	85,301	16,546	56.4%	25.3%	55.2%	10.7%
2006	79,471	14,534	85,696	15,133	1.7%	(10.8%)	0.5%	(8.5%)
2007	81,681	14,618	87,897	15,199	2.8%	0.6%	2.6%	0.4%
2008	79,515	13,758	86,306	14,322	(2.7%)	(5.9%)	(1.8%)	(5.8%)
2009	76,034	13,260	81,227	13,792	(4.4%)	(3.6%)	(5.9%)	(3.7%)
2010	79,611	15,504	85,518	15,904	4.7%	16.9%	5.3%	15.3%
2011	82,541	16,156	88,466	16,313	3.7%	4.2%	3.4%	2.6%
2012	87,011	16,212	92,135	16,052	5.4%	0.3%	4.1%	(1.6%)
2013	88,332	15,489	92,879	15,418	1.5%	(4.5%)	0.8%	(3.9%)
2014	89,099	15,763	94,471	15,677	0.9%	1.8%	1.7%	1.7%
2015	88,594	16,663	92,665	16,784	(0.6%)	5.7%	(1.9%)	7.1%
2016	88,601	17,229	93,551	17,498	0.0%	3.4%	1.0%	4.3%
2017	86,618	15,170	91,015	15,083	(2.2%)	(11.9%)	(2.7%)	(13.8%)
2018	90,308	15,982	94,351	16,142	4.3%	5.4%	3.7%	7.0%
2019	88,120	15,867	92,920	16,085	(2.4%)	(0.7%)	(1.5%)	(0.4%)
2020	84,584	16,016	90,059	16,233	(4.0%)	0.9%	(3.1%)	0.9%
2021	87,606	15,725	92,774	16,485	3.6%	(1.8%)	3.0%	1.6%
2022	88,884	15,689	94,301	16,047	1.5%	(0.2%)	1.6%	(2.7%)
2023	86,193	13,926	92,455	14,324	(3.0%)	(11.2%)	(2.0%)	(10.7%)
2024	89,274	15,630	94,787	15,766	3.6%	12.2%	2.5%	10.1%

PJM Real-Time Monthly Average Load

Figure 3-11 compares the real-time monthly average load plus exports of 2023 and 2024, with the historic five-year range. The real-time monthly average load plus exports in April, May, June, October and December 2024 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: 2023 through 2024

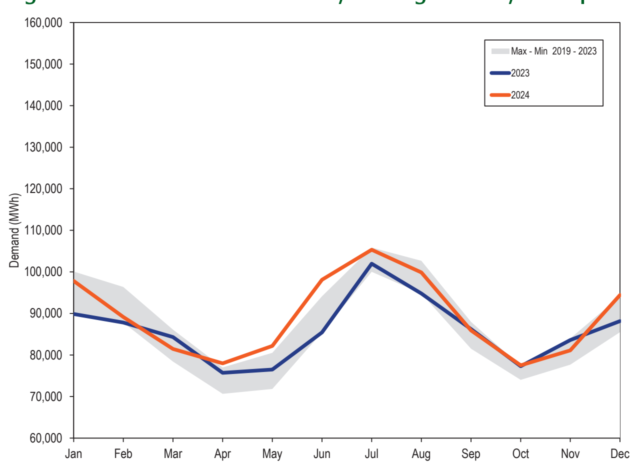

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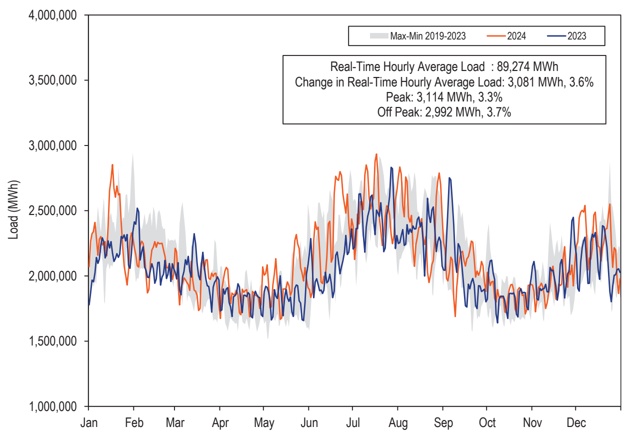
Figure 3-12 compares the real-time daily average load in 2023 and 2024, with the historic five year range. The daily average load was higher than the historic five year range in January, June, July, August and December.

Figure 3-12 Real-time daily load: 2023 through 2024



The real-time load is significantly affected by weather conditions. Table 3-9 compares the monthly heating and cooling degree days in 2023 and 2024.[40]

Heating degree days increased 1.9 percent compared to 2023. Cooling degree days increased 24.0 percent compared to 2023.

Table 3-9 Heating and cooling degree days: 2023 through 2024

	2023		2024		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	623.0	0.0	799.5	0.0	28.3%	0.0%
Feb	521.2	0.0	562.2	0.0	7.9%	0.0%
Mar	509.9	0.0	381.1	0.0	(25.3%)	0.0%
Apr	163.9	17.2	157.2	18.0	(4.1%)	4.5%
May	47.0	31.0	8.7	98.1	(81.5%)	216.9%
Jun	0.0	162.2	0.0	326.4	0.0%	101.3%
Jul	0.0	387.8	0.0	408.0	0.0%	5.2%
Aug	0.0	310.0	0.0	326.2	0.0%	5.2%
Sep	0.0	144.0	0.0	152.2	0.0%	5.7%
Oct	110.7	29.8	94.3	10.8	(14.8%)	(63.8%)
Nov	439.5	0.0	310.1	2.2	(29.4%)	0.0%
Dec	539.9	0.0	698.8	0.0	29.4%	0.0%
Total	2,955.1	1,081.8	3,011.9	1,341.9	1.9%	24.0%

Day-Ahead Demand

The day-ahead hourly average cleared demand in 2024, including DECs and UTCs, decreased by 5.2 percent from 2023, from 110,172 MWh to 104,393 MWh.

The day-ahead hourly average cleared demand in 2024, including DECs, UTCs and exports, decreased by 5.3 percent from 2023, from 114,044 MWh to 108,047 MWh.

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

- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero.
- **Up to Congestion Transaction (UTC).** A conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up to congestion transaction is evaluated as a matched pair of an injection and a withdrawal.
- **Export.** An external energy transaction scheduled from PJM to another balancing authority. An export must have a valid willing to pay congestion (WPC) OASIS reservation when offered. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an export energy transaction

40 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.

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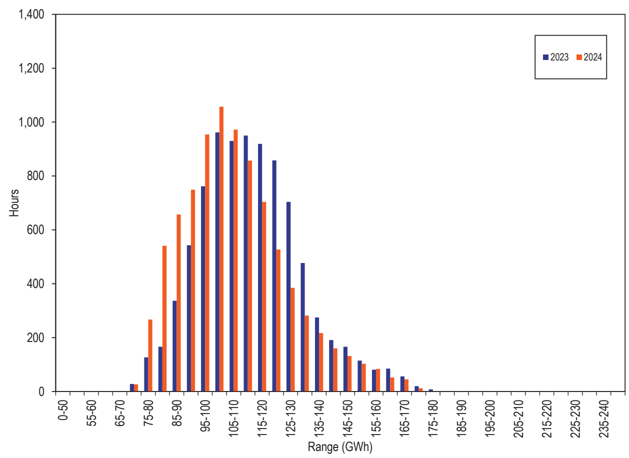
approved in the day-ahead energy market will not physically flow in real-time unless it is also submitted through the real-time energy market scheduling process.

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

PJM Day-Ahead Demand Duration

Figure 3-13 shows the hourly distribution of the day-ahead cleared demand in 2023 and 2024.

Figure 3-13 Distribution of day-ahead cleared demand plus exports: 2023 and 2024[41]



PJM Day-Ahead Average Demand

Table 3-10 shows day-ahead hourly average cleared demand for 2001 through 2024.

Table 3-10 Day-ahead hourly average cleared demand and demand plus exports: 2001 through 2024

	PJM Day-Ahead Demand (MWh)				Year to Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2001	33,370	6,562	33,757	6,431	NA	NA	NA	NA
2002	42,305	10,161	42,413	10,208	26.8%	54.8%	25.6%	58.7%
2003	44,674	7,841	44,807	7,811	5.6%	(22.8%)	5.6%	(23.5%)
2004	62,101	16,654	63,455	17,730	39.0%	112.4%	41.6%	127.0%
2005	93,534	17,643	96,447	17,952	50.6%	5.9%	52.0%	1.3%
2006	98,527	16,723	101,592	17,197	5.3%	(5.2%)	5.3%	(4.2%)
2007	105,503	16,686	108,932	17,030	7.1%	(0.2%)	7.2%	(1.0%)
2008	101,903	15,871	105,368	16,119	(3.4%)	(4.9%)	(3.3%)	(5.3%)
2009	94,941	15,869	98,094	15,999	(6.8%)	(0.0%)	(6.9%)	(0.7%)
2010	103,937	21,358	108,069	21,640	9.5%	34.6%	10.2%	35.3%
2011	113,866	20,708	117,681	20,929	9.6%	(3.0%)	8.9%	(3.3%)
2012	131,612	17,421	134,947	17,527	15.6%	(15.9%)	14.7%	(16.3%)
2013	144,858	18,489	148,132	18,570	10.1%	6.1%	9.8%	6.0%
2014	142,251	32,664	146,120	32,671	(1.8%)	76.7%	(1.4%)	75.9%
2015	111,644	18,716	114,827	18,872	(21.5%)	(42.7%)	(21.4%)	(42.2%)
2016	127,374	21,513	130,808	21,803	14.1%	14.9%	13.9%	15.5%
2017	125,794	19,402	128,757	19,625	(1.2%)	(9.8%)	(1.6%)	(10.0%)
2018	110,091	19,521	112,885	19,724	(12.5%)	0.6%	(12.3%)	0.5%
2019	112,588	18,163	115,444	18,386	2.3%	(7.0%)	2.3%	(6.8%)
2020	106,209	18,972	109,506	19,270	(5.7%)	4.5%	(5.1%)	4.8%
2021	97,537	17,869	100,642	18,359	(8.2%)	(5.8%)	(8.1%)	(4.7%)
2022	105,715	18,078	109,119	18,393	8.4%	1.2%	8.4%	0.2%
2023	110,172	17,919	114,044	18,111	4.2%	(0.9%)	4.5%	(1.5%)
2024	104,393	18,501	108,047	18,716	(5.2%)	3.2%	(5.3%)	3.3%

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

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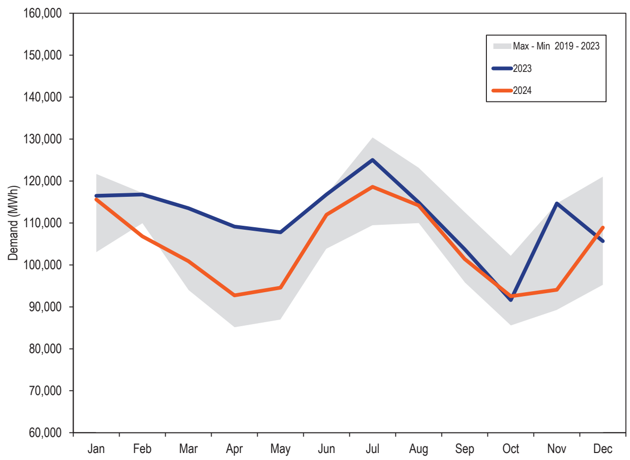
PJM Day-Ahead Monthly Average Demand

Figure 3-14 compares the day-ahead monthly average cleared demand including decrement bids and up to congestion transactions for 2023 and 2024, with the historic five-year range. In February 2024, the day-ahead monthly average cleared demand plus exports was lower than the minimum of the past five years, primarily as a result of the decrease in UTCs.

Figure 3-14 Day-ahead monthly average cleared demand plus exports: 2023 through 2024



Real-Time and Day-Ahead Demand

Table 3-11 presents summary statistics for day-ahead and real-time cleared demand for 2023 and 2024. The last two columns of Table 3-11 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 difference in the total physical day-ahead average load less the total physical real-time average load in 2024 decreased 216 MWh from 2023, from -734 MWh to -950 MWh. The total day-ahead average demand less the total real-time average demand in 2024 decreased 8,329 MWh from 2023, from 21,589 MWh to 13,260 MWh.

Table 3-11 Day ahead and real time demand (MWh): 2023 and 2024

		Day Ahead						Real Time		Day Ahead Less Real Time	
	Year	Fixed Demand	Price Sensitive	DEC Bids	Up to Congestion	Exports	Total Demand	Load	Total Demand	Load	Demand
Average	2023	85,016	443	4,749	19,964	3,873	114,044	86,193	92,455	(734)	21,589
	2024	87,954	370	5,295	10,774	3,655	108,047	89,274	94,787	(950)	13,260
Median	2023	83,260	418	4,339	19,578	3,861	112,905	84,179	90,300	(500)	22,606
	2024	85,301	369	5,077	10,435	3,607	105,630	86,686	92,055	(1,017)	13,575
Standard Deviation	2023	13,708	153	1,892	8,463	1,031	18,111	13,926	14,324	(65)	3,787
	2024	15,336	64	1,852	4,138	1,051	18,716	15,630	15,766	(229)	2,950
Peak Average	2023	92,400	470	5,406	21,991	3,881	124,148	93,341	99,573	(471)	24,574
	2024	95,407	382	5,908	12,602	3,622	117,920	96,455	101,743	(667)	16,177
Peak Median	2023	89,273	423	5,112	21,543	3,864	122,396	90,149	96,777	(453)	25,620
	2024	91,492	380	5,794	12,250	3,566	114,597	92,372	97,999	(500)	16,598
Peak Standard Deviation	2023	12,449	174	1,947	8,279	1,086	15,860	12,842	13,609	(220)	2,251
	2024	14,327	60	1,767	3,864	1,073	16,493	14,847	15,247	(460)	1,246
Off-Peak Average	2023	78,625	420	4,181	18,209	3,865	105,301	80,007	86,295	(962)	19,006
	2024	81,442	360	4,759	9,176	3,684	99,421	83,000	88,709	(1,198)	10,712
Off-Peak Median	2023	77,039	411	3,834	17,440	3,858	103,655	78,282	84,925	(833)	18,729
	2024	78,868	354	4,455	8,568	3,634	96,628	80,530	86,512	(1,308)	10,115
Off-Peak Standard Deviation	2023	11,332	128	1,643	8,226	981	15,147	11,687	11,861	(227)	3,286
	2024	13,055	66	1,756	3,684	1,030	16,099	13,444	13,546	(323)	2,553

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Figure 3-15 shows the average cleared volumes of day-ahead and real-time demand in 2024. 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): 2024

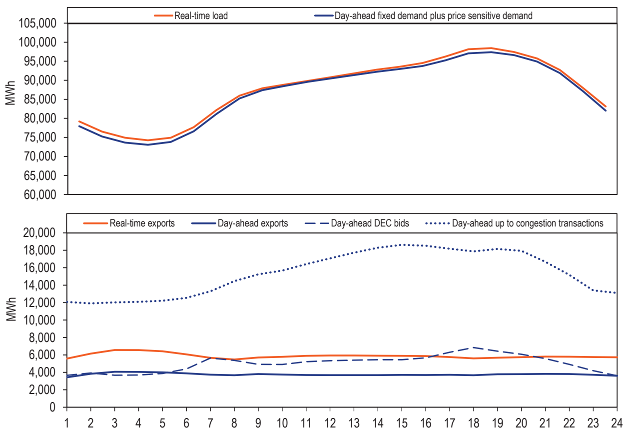

Figure 3-16 shows the difference between the physical day-ahead load and the physical real-time load, and the difference between the day-ahead demand including DECs, UTCs, and exports, and the real-time demand including exports, for 2023 and 2024.

Figure 3-16 Day-ahead minus real-time daily demand: 2023 through 2024

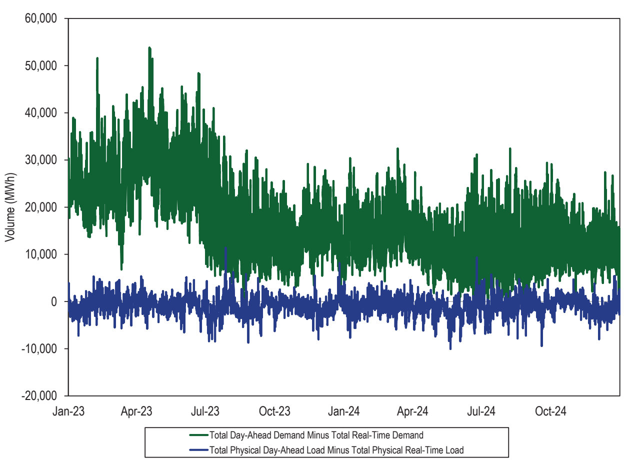

Figure 3-17 shows the difference between the day-ahead and real-time hourly average load by hour of the day. DECs, UTCs and exports are not included. The largest difference generally occurs during off peak hours, especially at hours beginning 1 and 2. The smallest difference generally occurs during peak 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): 2020 through 2024

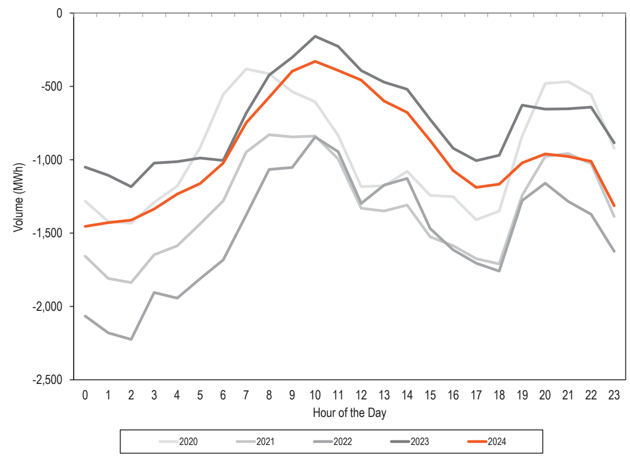

Figure 3-18 shows the difference between the day-ahead and real-time on peak and off peak hourly average load by month. DECs, UTCs and exports are not included.

Figure 3-18 Difference between day-ahead and real-time on peak and off peak hourly average load by month: 2020 through 2024

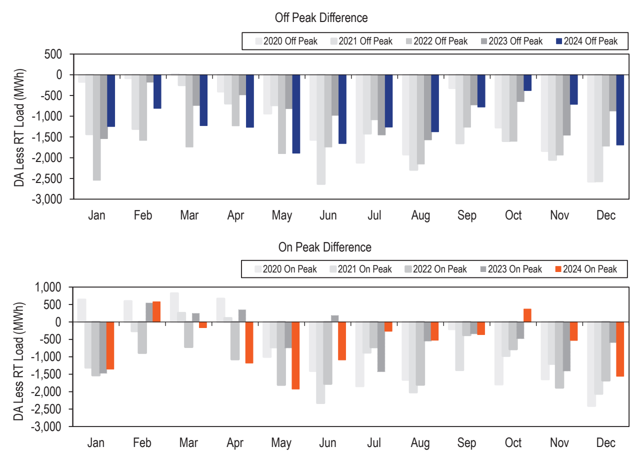

Table 3-12 shows the difference between the day-ahead and real-time on peak and off peak load by zone. DECs, UTCs and exports are not included. Some zones showed larger difference than other zones, such as DOM, BGE and APS. Some zones did not show a big difference

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between on peak or off peak, such as DOM and AEP. Some zones showed a significant difference between on peak or off peak, such as AECP, JCPL, and PENELEC.

Table 3-12 Difference between day-ahead and real-time on peak and off peak load by zone

	2023				2024			
	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	1.53	0.4%	18.60	2.4%	16.48	1.8%	40.46	4.1%
AEP	(81.81)	(0.5%)	(59.74)	(0.3%)	(86.39)	(0.6%)	(82.93)	(0.5%)
APS	(122.57)	(2.3%)	(64.50)	(1.0%)	(89.55)	(1.6%)	(11.08)	(0.1%)
ATSI	(60.99)	(0.7%)	39.75	0.7%	(82.89)	(1.0%)	69.13	1.1%
BGE	(94.48)	(3.0%)	(85.23)	(2.2%)	(119.45)	(3.6%)	(133.80)	(3.4%)
COMED	135.30	1.6%	157.99	1.6%	17.53	0.4%	34.54	0.5%
DAY	11.96	0.9%	19.48	1.1%	(9.21)	(0.2%)	(4.99)	0.0%
DOM	(594.70)	(4.9%)	(591.08)	(4.3%)	(428.76)	(3.3%)	(449.73)	(3.1%)
DPL	(25.94)	(1.3%)	(16.82)	(0.6%)	(36.32)	(1.8%)	(32.42)	(1.3%)
DUQ	19.20	1.5%	23.62	1.6%	4.78	0.3%	24.08	1.5%
EKPC/DEOK	(52.29)	(1.1%)	(42.03)	(0.8%)	(44.46)	(0.9%)	(25.43)	(0.4%)
JCPL	(22.80)	(0.8%)	52.71	3.0%	(45.19)	(1.7%)	48.47	3.0%
METED	10.22	0.9%	32.39	2.0%	11.12	1.0%	26.76	1.7%
PECO	26.81	1.0%	32.24	1.0%	(33.94)	(0.6%)	(26.07)	(0.3%)
PENELEC	19.70	1.3%	52.39	2.7%	(9.76)	(0.5%)	10.12	0.6%
PEPCO	(56.41)	(1.8%)	(46.09)	(1.2%)	(98.33)	(3.3%)	(107.10)	(3.0%)
PPL	32.24	1.0%	50.46	1.2%	17.69	0.6%	66.02	1.5%
PSEG	(91.48)	(2.0%)	(31.00)	(0.3%)	(163.83)	(3.5%)	(95.03)	(1.4%)
RECO	(2.17)	(1.2%)	(1.09)	0.1%	(4.04)	(2.8%)	(4.24)	(2.0%)

Table 3-13 shows the difference between the day ahead and real time 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. Some zones were under bidding by large such as DOM, AEP and BGE.

Table 3-13 Difference between day ahead and real time load by zone: 2020 through 2024

	2020		2021		2022		2023		2024	
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	(12.51)	(0.4%)	(35.99)	(2.2%)	(40.50)	(2.6%)	9.45	1.3%	27.66	2.9%
AEP	(205.68)	(1.5%)	(184.88)	(1.3%)	(175.12)	(1.3%)	(71.57)	(0.4%)	(84.78)	(0.6%)
APS	(73.55)	(1.2%)	(55.71)	(0.9%)	(125.11)	(2.2%)	(95.63)	(1.7%)	(52.96)	(0.9%)
ATSI	(9.02)	0.1%	(25.97)	(0.1%)	(106.72)	(1.4%)	(14.26)	(0.1%)	(12.00)	(0.0%)
BGE	(134.57)	(3.8%)	(137.84)	(3.8%)	(87.14)	(2.5%)	(90.19)	(2.6%)	(126.14)	(3.5%)
COMED	83.92	1.0%	(46.06)	(0.2%)	13.77	0.3%	145.83	1.6%	25.46	0.5%
DAY	0.44	0.3%	(8.69)	(0.3%)	(28.16)	(1.2%)	15.45	1.0%	(7.24)	(0.1%)
DOM	(290.24)	(2.6%)	(522.40)	(4.4%)	(599.31)	(4.8%)	(593.02)	(4.6%)	(438.53)	(3.2%)
DPL	(32.28)	(1.4%)	(43.78)	(1.9%)	(71.08)	(3.4%)	(21.71)	(1.0%)	(34.50)	(1.6%)
DUQ	16.25	1.4%	(2.38)	(0.0%)	(78.42)	(5.0%)	21.25	1.6%	13.78	0.9%
EKPC/DEOK	(45.76)	(1.0%)	(53.31)	(1.0%)	(84.23)	(1.8%)	(47.53)	(1.0%)	(35.58)	(0.6%)
JCPL	(18.65)	0.0%	(34.69)	(0.7%)	(47.31)	(1.2%)	12.23	0.9%	(1.51)	0.5%
METED	(29.83)	(1.4%)	(22.84)	(1.0%)	(64.01)	(3.4%)	20.50	1.4%	18.41	1.3%
PECO	(37.17)	(0.5%)	(47.27)	(0.7%)	81.81	2.1%	29.33	1.0%	(30.27)	(0.5%)
PENELEC	(5.04)	(0.2%)	9.77	0.5%	10.06	0.5%	34.87	2.0%	(0.49)	0.1%
PEPCO	(14.51)	(0.1%)	(20.55)	(0.4%)	(12.70)	(0.3%)	(51.62)	(1.5%)	(102.42)	(3.2%)
PPL	(39.34)	(0.7%)	(48.06)	(0.8%)	20.25	0.7%	40.69	1.1%	40.23	1.0%
PSEG	(95.22)	(1.7%)	(33.23)	(0.5%)	(91.37)	(1.7%)	(63.42)	(1.2%)	(131.75)	(2.5%)
RECO	5.38	4.1%	2.60	1.6%	0.23	0.4%	(1.67)	(0.6%)	(4.14)	(2.4%)

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Market Behavior

Generator Offers

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

The Must Run column in Table 3-14 is the submitted offer MW of units offering with must run commitment status. The Eco Min column in Table 3-14 is the economic minimum MW of units offering with economic commitment status. The dispatchable range in Table 3-14 is the percent of MW offered by price range, between the economic minimum MW and economic maximum MW for all available units. Some units, like wind and solar, offer a dispatchable range in the day-ahead market although their availability in real time is determined by the presence of sun and wind rather than economics.

Units may designate all or a portion of their capacity as emergency MW. Table 3-14 shows that 0.2 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 2024, 23.2 percent of MW were offered as must run, 32.1 percent of MW were offered as the economic minimum MW for dispatchable units, 44.6 percent of MW were offered as dispatchable, and 0.2 percent of MW were offered as emergency maximum MW.

Table 3-14 Dispatchable status of day-ahead energy offers: 2024

			Dispatchable Range											
Unit Type	Must Run	Eco Min	($300) - $0	$0 - $25	$25 - $50	$50 - $75	$75 - $100	$100 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1000	Emergency MW	Dispatchable Percent
CC	8.6%	35.4%	(0.1%)	35.8%	11.8%	2.0%	1.1%	3.0%	2.0%	0.1%	0.0%	0.0%	0.1%	55.9%
CT	0.4%	58.7%	0.1%	3.2%	14.8%	6.4%	2.2%	5.7%	7.4%	0.5%	0.0%	0.1%	0.3%	40.6%
Diesel	7.8%	82.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	10.1%	0.0%	0.0%	0.0%	0.0%	10.1%
Hydro	81.6%	0.4%	18.0%	(0.0%)	0.0%	0.0%	(0.0%)	(0.0%)	0.0%	(0.0%)	0.0%	0.0%	0.0%	18.0%
Nuclear	87.9%	9.5%	2.0%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.6%
Solar	16.4%	0.3%	66.4%	7.0%	5.5%	2.2%	0.7%	0.8%	0.6%	0.1%	0.0%	0.1%	0.0%	83.3%
Steam - Coal	29.6%	24.1%	0.1%	11.1%	25.1%	4.6%	0.6%	1.0%	1.0%	2.4%	0.0%	(0.0%)	0.3%	46.0%
Steam - Other	4.9%	21.5%	1.8%	14.5%	18.2%	6.8%	1.5%	7.6%	22.9%	0.3%	0.0%	0.0%	0.1%	73.5%
Wind	3.1%	0.4%	72.9%	9.4%	7.3%	1.7%	2.7%	0.4%	0.3%	1.3%	0.1%	0.3%	0.0%	96.4%
Other	13.4%	50.8%	5.5%	7.7%	3.9%	0.0%	0.0%	0.5%	15.9%	0.5%	0.0%	0.0%	1.7%	34.2%
All Units	23.2%	32.1%	2.5%	16.9%	12.7%	3.3%	1.1%	3.1%	4.4%	0.6%	0.0%	0.0%	0.2%	44.6%

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.

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Table 3-15 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 2024, an average of 365 units per day made hourly offers, an increase of 17 units from 2023. In 2024, 591 units opted in for intraday offer updates, an increase of 42 units from 2023. In 2024, an average of 147 units made intraday offer updates each day, an increase of 12 units from 2023.

Table 3-15 Daily average number of units making hourly offers, opted in for intraday offers and making intraday offer updates: 2023 and 2024

	Fuel Type	2023	2024	Difference
Hourly Offers	Natural Gas	315	319	4
	Other Fuels	33	46	13
	Total	348	365	17
Opt In	Natural Gas	422	434	12
	Other Fuels	127	157	30
	Total	549	591	42
Intraday Offer Updates	Natural Gas	131	143	12
	Other Fuels	4	4	0
	Total	135	147	12
Total Units with nonzero offers		827	836	9

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.[42] 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.

Unlike all other generation capacity resources, Intermittent Resources, Capacity Storage Resources, and Hybrid Resources consisting exclusively of components that in isolation would be Intermittent Resources or Capacity Storage Resources, are categorically exempt from the RPM must offer requirement. Capacity Storage Resources include pumped storage hydroelectric, impoundment hydroelectric, flywheel, and battery. Intermittent Resources include wind, solar, landfill gas, run of river hydroelectric, and other renewable resources. As a result, a significant level of such resources withhold their capacity. The result is to increase the clearing prices above the competitive level. This can benefit the owners of capacity portfolios that include such resources as well as resources with an RPM 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.

The current enforcement of the ICAP must offer requirement is inadequate.[43] 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) after the fact. The three applications are not linked and there is no formal process to ensure consistency.

For example, ambient ratings are an issue. When the weather is hotter than test conditions, the capacity of some units is reduced below the ICAP levels. While this fact may be reported by unit owners in eDART and reflected in lower offered MW in the energy market, the derates are not reported as outages in eGADS and are therefore not included as outages for purposes of defining capacity using EFORd. For planning purposes, PJM acknowledges this discrepancy, but instead of reflecting the derates in the supply offers from the units that are actually derated, PJM increases the demand for capacity to account for the loss of supply due to ambient derates.[44]

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

42 OA Schedule 1 § 1.10.1A(d).

43 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.

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

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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. This proposal was implemented on November 15, 2023.[45]

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

Table 3-16 shows average hourly MW, for each month, that violated the ICAP must offer requirement in 2024. On average for all hours, 2,290 MW did not meet the ICAP must offer requirement, but for 10 percent of the hours, 3,336 MW did not meet the must offer requirement. These MW levels are larger than the reserve shortages that trigger scarcity pricing and larger than most supply contingencies that lead to synchronized reserve events.

Table 3-16 Average hourly estimated capacity (MW) failing the ICAP must offer requirement: 2024

Month	90th Percentile	Average	10th Percentile
Jan-24	2,434	1,785	1,228
Feb-24	2,099	1,659	1,307
Mar-24	3,396	2,815	2,409
Apr-24	2,251	1,700	1,188
May-24	3,323	2,513	1,803
Jun-24	3,314	2,238	1,343
Jul-24	3,394	2,325	1,357
Aug-24	2,885	1,865	806
Sep-24	3,272	2,322	985
Oct-24	3,476	2,726	2,034
Nov-24	3,950	2,498	920
Dec-24	3,910	2,983	2,054
2024	3,336	2,290	1,292

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.[46]

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.[47]

The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy.[48] 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.

45 *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>.

46 See 151 FERC ¶ 61,208 at P 476 (2015).

47 OA Schedule 1 § 1.10.1A(d).

48 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).

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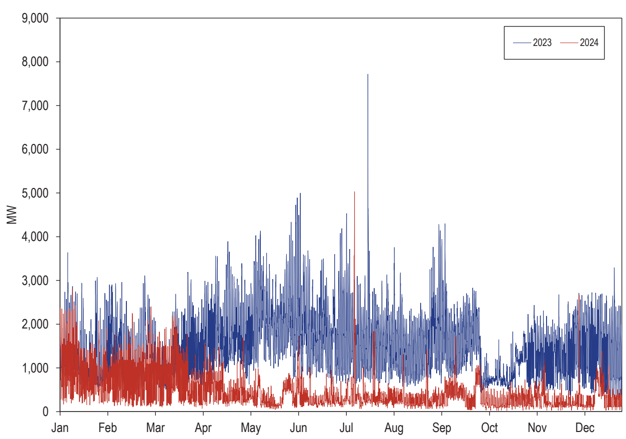
Table 3-17 shows average hourly maximum emergency MW, for each month. The levels of maximum emergency MW change hourly, daily and seasonally. For example, in January 2024, 10 percent of hours had maximum emergency MW greater than or equal to 1,850 MW while 10 percent of hours had maximum emergency MW less than 363. The hourly average, in 2024, was 662 MW offered as maximum emergency, 58.6 percent lower than in 2023.

Table 3-17 Maximum emergency MW by month: 2024

Month	90th Percentile	Average	10th Percentile
Jan-24	1,850	1,025	363
Feb-24	1,480	880	239
Mar-24	1,538	888	227
Apr-24	936	530	205
May-24	603	333	120
Jun-24	586	315	133
Jul-24	553	384	174
Aug-24	459	285	132
Sep-24	708	407	120
Oct-24	485	253	97
Nov-24	473	254	101
Dec-24	657	320	107
2024	1,129	662	122

Figure 3-19 shows maximum emergency MW by hour in 2023 and 2024. The continued reduction of the use of emergency maximum in 2024 is mainly a result of improved compliance with the maximum emergency rules.

Figure 3-19 Maximum Emergency MW by hour: 2023 and 2024



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.[49] [50]

PJM raised the schedule selection issues in the stakeholder process to address computational time in the day-ahead market. PJM's original proposal would

49 See 175 FERC ¶ 61,231 (2021).
50 See 185 FERC ¶ 61,158 (2023).

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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.[51] 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.[52] FERC accepted PJM's proposal that has no specific plans to implement the improved rules and instead links implementation to PJM's long awaited 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 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 2024. The analysis includes units with technologies that are subject to parameter limits and offer both price-based and cost-based schedules.[53] Table 3-18 shows the number and percentage of day-ahead unit run hours that failed the TPS test but were committed on price schedules. Table 3-18 shows that 27.7 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.

51 187 FERC 61,051 at P 25 (2024).
52 See 189 FERC ¶ 61,060 (2024).
53 Nuclear, wind, solar and hydro units are not subject to parameter limits.

Table 3-18 Parameter mitigation for units failing the day-ahead TPS test: 2024

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	27,425	27.7%
Committed on price schedule as flexible as cost	7,164	7.2%
Committed on cost (cost capped)	60,806	61.4%
Committed on price PLS	3,565	3.6%
Total committed on schedule as flexible as cost	71,535	72.3%
Total failed TPS test commitments	98,960	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 2024. PJM declared cold weather alerts on 10 days and hot weather alerts on 28 days in 2024. 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 3-19 shows that 34.4 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 3-19 Parameter mitigation during weather alerts: 2024

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	59,593	34.4%
Committed on price schedule as flexible as PLS	11,133	6.4%
Committed on cost (cost capped)	7,358	4.3%
Committed on price PLS	94,929	54.9%
Total committed on schedule as flexible as PLS	113,420	65.6%
Total weather alert commitments	173,013	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

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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.

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. This would require that PJM apply the full set of approved unit specific flexible parameters to a resource that makes any price-based offer under these conditions. The selection of a cost offer, based on the financial parameters, would include the PLS parameters for all schedules.

Currently, PJM commits units on either a cost-based or a price-based schedule. 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.[54] [55]

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

55 *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>.

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.[56] 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 3-20 shows, for the delivery year beginning June 1, 2024, the number of units with approved unit specific parameter limits, and the number of units that used the default parameter limits published by PJM.

Table 3-20 Adjusted unit specific parameter limit statistics: 2024/2025 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	118	37	23.9%
Frame CT	156	106	40.5%
Combined Cycle	93	27	22.5%
Reciprocating Internal Combustion Engines	57	3	5.0%
Solid Fuel NUG	33	6	15.4%
Oil and Gas Steam	10	23	69.7%
Subcritical and Supercritical Coal Steam	7	65	90.3%
Total	474	267	36.0%

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.[57]

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.[58] 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.[59]

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.[60] The order primarily addressed limits imposed by natural gas pipelines. The Commission directed PJM to submit tariff language to establish a process through which capacity performance resources that operate outside the defined unit specific parameter

56 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>.

57 *See* OA Schedule 1 § 6.6(i) and PJM Manual 11, Section 2.3.4.3.

58 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>.

59 *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>.

60 151 FERC ¶ 61,208 at P 437 (2015).

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limits can justify such operation and therefore remain eligible for make whole payments.[61]

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 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 fact that a contract may be entered into by two willing parties, or that a generator chooses a specific type of service under the pipeline tariff does not mean that is the only possible arrangement between the two parties or that it is consistent with an efficient market outcome or that a contract or pipeline tariff term can reasonably impose costs on customers who were not party to the contract. The actual contractual or tariff terms are a function of the incentives and interests of the parties, who may be affiliates or have market power. The fact that a just and reasonable contract exists between a generation owner and a gas supplier does not mean that it is appropriate or efficient to impose the resultant costs on electric customers or that it incorporates an efficient allocation of performance risk between the generation owner and other market participants.

The approach to parameters defined in the June 9th Order will increase energy market uplift payments substantially. While some uplift is necessary and efficient in an LMP market, this uplift is not. Electric customers are not in a position to determine the terms of the contracts that resources enter into. Customers rely on the market rules to create incentives that protect them by assigning operational risk to generators, who are in the best position to efficiently manage those risks.

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

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

The June 9th Order pointed out that the way to ensure that a resource's parameters are exposed to market consequences is to not allow any parameter limitations as an excuse for nonperformance. The same logic should apply to energy market uplift rules. A resource's

61 *Id.* at P 440.

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parameters should be exposed to market consequences and the resource should not be made whole if it is operating less flexibly than the reference resource. Paying energy market uplift on the basis of parameters consistent with the flexibility goals of the capacity performance construct would ensure that performance incentives are consistent across the capacity and energy markets and ensure that performance risk is appropriately assigned to generation owners.

Parameter Impacts of Gas Pipeline Conditions

During extreme cold weather conditions, and more recently, also during hot weather conditions, a number of gas fired generators request temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters affected include notification time, minimum run time (MRT) and turn down ratio (TDR, the ratio of economic maximum MW to economic minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may, depending on the nature of the transportation service purchased, be forced to nominate an equal amount of gas for each hour in a 24 hour period, with penalties for deviating from the nominated quantity. This leads to requests for 24 hour minimum run times and turn down ratios close to 1.0, to avoid deviations from the hourly nominated quantity. The frequency of 24 hour minimum run time requests increased after Winter Storm Elliott in December 2022. Table 3-21 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 2024, there were 79 units in PJM with a total installed capacity of 10,476 MW that requested a 24 hour minimum run time on their parameter limited schedules based on pipeline restrictions.

Table 3-21 Units with 24 hour minimum run times due to gas pipeline restrictions: 2018 through 2024

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

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 3-68.) 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 2024, PJM paid $30.2 million in Day-Ahead uplift to gas fired units with a 24 hour minimum run time, primarily during Winter Storm Gerri in the PEPCO Zone.

After observing the misuse of and the failure to use temporary exceptions during Winter Storm Elliott, on September 8, 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.[62] 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.

62 *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>.

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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 can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. Because virtual positions do not require physical generation or load, participants must buy or sell out of their virtual positions at real-time energy market prices. On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, interfaces and residual aggregate metered load nodes, and limiting the eligible bidding points for INCs and DECs to the same nodes plus active generation and load nodes.[63] Up to congestion transactions may be submitted between any two aggregates on a list of 46 aggregates eligible for up to congestion transaction bidding.[64] 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 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 2024.

Figure 3-20 Day-ahead aggregate supply curves: 2024 example day

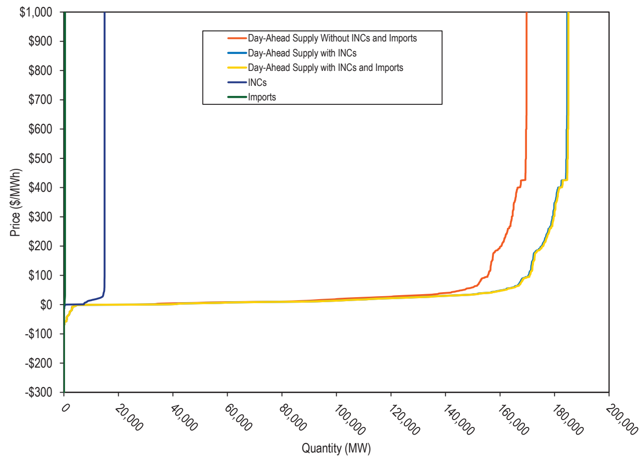

Table 3-22 shows the hourly average number of cleared and submitted increment offers and decrement bids by month in 2023 and 2024.[65] The hourly average submitted increment offer MW increased by 23.6 percent and cleared increment MW increased by 18.0 percent in 2024 compared to 2023. The hourly average submitted decrement bid MW increased by 22.2 percent and cleared decrement MW increased by 7.9 percent in 2024 compared to 2023.

63 162 FERC ¶ 61,139 (2018), *reh'g denied*, 164 FERC ¶ 61,170 (2018).

64 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>.

65 Table 3-22 uses cleared day-ahead market data while final settlements data is used elsewhere in this report.

Table 3-22 Average hourly number of cleared and submitted INCs and DECs by month: January 2023 through December 2024

		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
2023	Jan	3,870	7,847	319	949	4,421	9,941	307	1,076
2023	Feb	4,994	9,786	426	1,190	4,583	9,732	258	933
2023	Mar	4,578	9,008	415	1,068	4,613	11,030	316	1,113
2023	Apr	4,960	10,697	374	1,036	3,515	9,803	275	1,091
2023	May	4,648	9,200	393	1,050	4,126	10,193	284	984
2023	Jun	4,171	8,328	374	1,008	5,515	11,400	426	1,272
2023	Jul	3,421	8,403	278	952	5,725	11,608	593	1,590
2023	Aug	3,177	8,604	283	953	6,267	11,679	337	1,013
2023	Sep	3,939	9,612	366	1,060	5,472	11,539	291	961
2023	Oct	5,832	11,275	463	1,270	4,072	10,237	281	1,010
2023	Nov	4,874	9,017	429	1,375	3,867	8,637	238	884
2023	Dec	4,620	9,610	404	1,382	4,771	9,689	273	958
2023	Annual	4,418	9,277	376	1,107	4,748	10,464	324	1,075
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

Table 3-23 shows the average hourly number of up to congestion transactions and the average hourly MW by month in 2023 and 2024. The hourly average submitted up to congestion bid MW decreased by 54.9 percent and cleared up to congestion bid MW decreased by 46.0 percent in 2024 compared to 2023.

Table 3-23 Average hourly cleared and submitted up to congestion bids by month: January 2023 through December 2024

		Up to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2023	Jan	23,708	69,113	952	2,522
2023	Feb	24,242	87,218	1,003	3,156
2023	Mar	24,834	115,463	961	3,942
2023	Apr	30,027	129,360	1,043	3,719
2023	May	27,910	110,474	1,053	3,251
2023	Jun	26,248	90,763	1,106	3,242
2023	Jul	18,777	59,561	1,011	2,715
2023	Aug	12,567	36,486	830	2,035
2023	Sep	12,574	34,771	686	1,539
2023	Oct	10,810	34,122	580	1,402
2023	Nov	14,929	38,277	685	1,460
2023	Dec	13,494	31,414	638	1,339
2023	Annual	19,964	69,561	878	2,522
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

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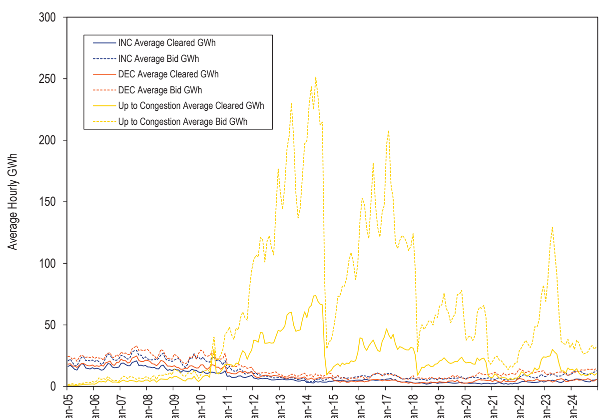
Table 3-24 shows the average hourly number of day-ahead import and export transactions and the average hourly MW in 2023 and 2024.[66] In 2024, the average hourly submitted import transaction MW decreased by 1.4 percent and the average hourly cleared import transaction MW decreased by 4.3 percent compared to 2023. In 2024, the average hourly submitted export transaction MW decreased by 5.4 percent and the average hourly cleared export transaction MW decreased by 6.1 percent compared to 2023.

Table 3-24 Hourly average day-ahead number of cleared and submitted import and export transactions by month: January 2023 through December 2024

		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
2023	Jan	740	843	7	8	3,879	3,944	28	28
2023	Feb	646	696	6	6	4,065	4,087	29	29
2023	Mar	371	403	3	4	3,740	3,780	28	29
2023	Apr	368	377	4	4	3,041	3,055	25	26
2023	May	355	373	4	4	2,902	2,904	21	21
2023	Jun	319	333	4	4	4,488	4,497	32	32
2023	Jul	154	165	3	3	4,610	4,637	34	35
2023	Aug	124	134	2	2	4,666	4,675	34	34
2023	Sep	205	247	3	4	4,040	4,068	29	30
2023	Oct	647	750	7	8	3,171	3,199	22	23
2023	Nov	540	647	6	7	3,559	3,597	30	31
2023	Dec	241	321	3	4	4,571	4,585	34	35
2023	Annual	392	440	4	5	3,894	3,919	29	29
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

Figure 3-21 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month from 2005 through December 2024. 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 December 2024.

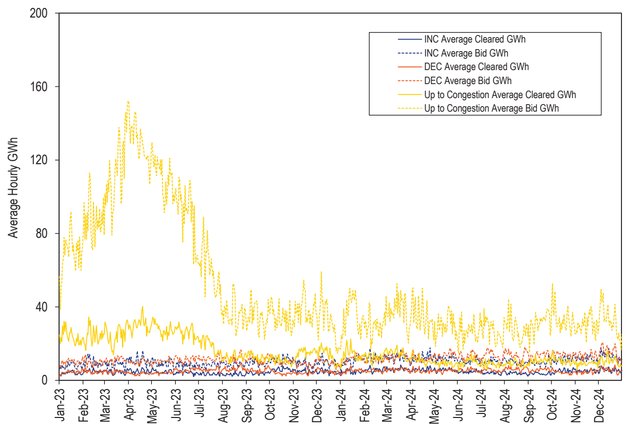
Figure 3-21 Monthly bid and cleared INCs, DECs and UTCs (GWh): January 2005 through December 2024



66 Table 3-24 uses cleared day-ahead market data, while final settlements data is used elsewhere in this report.

Figure 3-22 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 2023 through December 2024.

Figure 3-22 Daily bid and cleared INCs, DECs, and UTCs (GWh): January 2023 through December 2024



In order to evaluate the ownership of virtual bids, the MMU categorizes all participants making virtual bids in PJM as either physical or financial. Physical entities include utilities and customers that primarily take physical positions in PJM markets. Financial entities include banks and hedge funds that primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are 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 2024 increased 1.4 percent compared to 2023, and continued to make up the majority of all INCs and DECs.

Table 3-25 shows, in 2023 and 2024, the total increment offers and decrement bids and cleared MW by type of parent organization.

Table 3-25 INC and DEC bids and cleared MWh by type of parent organization (MWh): January through December, 2023 and 2024

	2023				2024			
Category	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	156,697,905	90.6%	67,323,444	83.8%	197,265,322	92.3%	76,977,531	85.3%
Physical	16,234,228	9.4%	12,976,658	16.2%	16,443,681	7.7%	13,292,731	14.7%
Total	172,932,133	100.0%	80,300,102	100.0%	213,709,003	100.0%	90,270,262	100.0%

Table 3-26 shows the total up to congestion bid and cleared MWh by type of parent organization in 2023 and 2024 by month. Up to congestion bids submitted by financial entities decreased significantly in 2024 compared to 2023, from 606.1 million MWh to 269.4 million MWh, while up to congestion bids submitted by physical entities increased by 2.8 million MWh. Financial entities submitted 97.8 percent of all up to congestion bids, down from 99.5 percent, and cleared 97.8 percent of all up to congestion bids, down from 98.8 percent. In 2024, almost all up to congestion trading activity was by financial participants.

Table 3-26 Up to congestion transactions by type of parent organization (MWh): 2023 and 2024

	2023				2024			
Category	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent
Financial	606,126,895	99.5%	172,797,198	98.8%	269,446,396	97.8%	91,282,692	96.5%
Physical	3,223,571	0.5%	2,086,789	1.2%	6,069,544	2.2%	3,352,487	3.5%
Total	609,350,466	100.0%	174,883,987	100.0%	275,515,940	100.0%	94,635,178	100.0%

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Table 3-27 shows the total import and export transactions by type of parent organization in 2023 and 2024. The majority of import and export transactions in both day ahead and real time were submitted by physical entities in 2024.

Table 3-27 Import and export transactions by type of parent organization (MWh): 2023 and 2024

		2023		2024	
	Category	Total Import and Export MWh	Percent	Total Import and Export MWh	Percent
Day-Ahead	Financial	11,900,657	32.0%	9,563,003	27.1%
	Physical	25,259,700	68.0%	25,673,098	72.9%
	Total	37,160,357	100.0%	35,236,101	100.0%
Real-Time	Financial	17,974,299	25.7%	15,996,783	24.9%
	Physical	51,841,862	74.3%	48,175,482	75.1%
	Total	69,816,160	100.0%	64,172,265	100.0%

Table 3-28 shows the top 10 locations by total cleared INC and DEC MWh in 2023 and 2024. The top 10 locations included four hubs, four interface pricing points, and two residual metered load aggregates.

Table 3-28 Virtual offers and bids by top 10 locations (MWh): January through December, 2023 and 2024

2023					2024				
Aggregate/Bus Name	Aggregate/Bus Type	INC MWh	DEC MWh	Total MWh	Aggregate/Bus Name	Aggregate/Bus Type	INC MWh	DEC MWh	Total MWh
MISO	INTERFACE	232,220	8,159,891	8,392,111	WESTERN HUB	HUB	3,306,443	2,150,025	5,456,468
WESTERN HUB	HUB	4,013,716	2,394,533	6,408,248	MISO	INTERFACE	200,925	4,212,875	4,413,800
SOUTH	INTERFACE	3,466,344	471,858	3,938,202	SOUTH	INTERFACE	3,630,636	472,798	4,103,434
N ILLINOIS HUB	HUB	1,839,079	687,459	2,526,539	N ILLINOIS HUB	HUB	2,692,615	779,736	3,472,351
DOM_RESID_AGG	RESIDUAL METERED EDC	231,323	2,268,107	2,499,430	NYIS	INTERFACE	677,691	1,972,771	2,650,461
NYIS	INTERFACE	651,564	1,437,517	2,089,081	AEP-DAYTON HUB	HUB	914,264	1,415,935	2,330,200
LINDENVFT	INTERFACE	32,069	1,773,299	1,805,367	DOM_RESID_AGG	RESIDUAL METERED EDC	310,119	1,508,116	1,818,235
AEP-DAYTON HUB	HUB	870,158	891,838	1,761,996	LINDENVFT	INTERFACE	35,443	1,625,458	1,660,900
BGE_RESID_AGG	RESIDUAL METERED EDC	466,859	997,169	1,464,028	BGE_RESID_AGG	RESIDUAL METERED EDC	507,130	1,083,765	1,590,894
EASTERN HUB	HUB	266,830	777,894	1,044,724	EASTERN HUB	HUB	377,483	929,838	1,307,321
Top ten total		12,070,161	19,859,564	31,929,725			12,652,749	16,151,317	28,804,065
PJM total		38,704,078	41,596,024	80,300,102			43,759,047	46,511,215	90,270,262
Top ten total as percent of PJM total		31.2%	47.7%	39.8%			28.9%	34.7%	31.9%

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Table 3-29 shows up to congestion transactions for the top 10 source and sink pairs and associated source, sink and overall profits on each path in 2023 and 2024. Total profits for up to congestion transactions in 2024 were $0.2 million, a decrease of 99.4 percent compared to profits of $41.2 million in 2023.[67] The UTCs from DOMINION HUB to DOM_RESID_AGG constituted 10.3 percent of all UTC volume in 2024, despite losing $5.7 million.

Table 3-29 Cleared up to congestion bids by top 10 source and sink pairs (MWh): 2023 and 2024[68]

				2023			
				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	37,091,596	$29,331,269	$1,374,633	$22,748,666
AEP GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	5,691,101	$3,414,773	($775,593)	$1,523,495
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	4,882,193	$4,910,522	($2,005,043)	$1,957,894
CHICAGO GEN HUB	HUB	MISO	INTERFACE	3,616,885	$2,294,702	($1,803,739)	($175,370)
CHICAGO GEN HUB	HUB	CHICAGO HUB	HUB	3,008,529	$3,551,163	($3,008,130)	$4,598
CHICAGO GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	2,691,535	$2,265,240	($202,247)	$1,459,537
COMED_RESID_AGG	AGGREGATE	AEPIM_RESID_AGG	AGGREGATE	2,298,131	$1,888,629	($1,032,468)	$499,896
APS_RESID_AGG	AGGREGATE	DOM_RESID_AGG	AGGREGATE	2,169,528	$3,110,470	($90,455)	$2,506,878
AEP GEN HUB	HUB	DOM_RESID_AGG	AGGREGATE	1,927,663	$2,248,276	$70,000	$1,809,806
CHICAGO GEN HUB	HUB	OHIO HUB	HUB	1,854,636	$1,565,236	($1,382,464)	($201,919)
Top ten total				65,231,797	$54,580,281	($8,855,506)	$32,133,479
PJM total				174,883,987	$183,734,980	($106,355,194)	$41,200,757
Top ten total as percent of PJM total				37.3%	29.7%	8.3%	78.0%
				2024			
				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	9,756,243	$9,264,445	($11,147,212)	($5,746,334)
CHICAGO GEN HUB	HUB	CHICAGO HUB	HUB	4,654,340	($1,341,325)	$5,041,029	$1,887,727
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	4,605,852	$2,657,880	$2,469,216	$3,722,900
AEP GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	2,190,684	$7,928	$984,868	$273,766
CHICAGO GEN HUB	HUB	OHIO HUB	HUB	2,020,702	$2,149,155	$106,743	$1,530,013
CHICAGO GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	1,847,495	$3,257,362	($851,697)	$1,594,699
CHICAGO GEN HUB	HUB	MISO	INTERFACE	1,735,806	($277,141)	$305,641	($510,402)
CHICAGO GEN HUB	HUB	DEOK_RESID_AGG	AGGREGATE	1,309,861	$1,551,688	($566,589)	$429,895
CHICAGO GEN HUB	HUB	N ILLINOIS HUB	HUB	1,299,384	($2,671,649)	$4,027,767	$835,085
UGI_RESID_AGG	AGGREGATE	NYIS	INTERFACE	1,164,041	($834,046)	$1,169,731	($114,519)
Top ten total				30,584,407	$13,764,297	$1,539,497	$3,902,829
PJM total				94,635,178	$63,022,670	($24,820,745)	$236,398
Top ten total as percent of PJM total				32.3%	21.8%	(6.2%)	1,651.0%

Table 3-30 shows the average daily number of distinct source-sink pairs that were offered and cleared each month from January 2023 through December 2024. The average number of submitted source-sink pairs per day decreased from 1,624 source-sink pairs submitted in 2023 to 1,250 in 2024. The average number of cleared source-sink pairs per day decreased from 1,257 in 2023 to 1,008 per day in 2024.

67 The source and sink aggregates in these tables refer to the name and location of a bus and do not include information about the behavior of any individual market participant.

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

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Table 3-30 Number of offered and cleared UTC source and sink pairs: January 2023 through December 2024

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2023	Jan	1,558	1,723	1,239	1,480
2023	Feb	1,705	1,812	1,326	1,522
2023	Mar	1,803	1,922	1,318	1,561
2023	Apr	1,756	1,909	1,327	1,550
2023	May	1,729	1,930	1,321	1,646
2023	Jun	1,820	1,886	1,416	1,607
2023	Jul	1,857	1,959	1,475	1,643
2023	Aug	1,748	1,907	1,372	1,657
2023	Sep	1,607	1,853	1,251	1,605
2023	Oct	1,465	1,752	1,121	1,392
2023	Nov	1,223	1,660	997	1,406
2023	Dec	1,212	1,474	921	1,266
2023	Annual	1,624	1,816	1,257	1,528
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

Table 3-31 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 2023 and 2024. Total cleared up to congestion transactions decreased by 45.9 percent from 174.9 million MWh in2023 to 94.6 million MWh in 2024. Internal up to congestion transactions in 2024 were 83.1 percent of all up to congestion transactions, a decrease from 84.9 percent in 2023.

Figure 3-23 shows the total volume of import, export, wheel, and internal up to congestion transactions by month from January 2005 through December 2024. An initial increase and continued increase in internal up to congestion transactions by month followed the November 1, 2012, rule change permitting such transactions, until September 8, 2014. The reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed.[69] There was an increase in up to congestion volume as a result of the expiration of the 15 month refund period for the proceeding related to uplift charges for UTC transactions. In 2018, total UTC activity and the percent of marginal up to congestion transactions again decreased significantly as the result of a FERC order issued on February 20, 2018, and implemented on February 22, 2018.[70] The order limited UTC trading to hubs, residual metered load, and interfaces. UTC activity increased following that reduction.

UTC activity decreased again beginning November 1, 2020, after a FERC order requiring UTCs to pay day-ahead and balancing operating reserve charges equivalent to a DEC at the UTC sink point became effective on that date.[71] In 2022 and the first six months of 2023, the volume of cleared UTCs increased significantly, primarily internal transactions. The volume of cleared UTCs decreased consistently July 2023 through December 2024.

Table 3-31 Cleared up to congestion transactions and share of top 10 paths by type (MW):2023 and 2024

	2023				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	5,890,651	8,097,070	2,489,740	63,282,170	79,759,631
PJM total (MW)	10,071,049	13,650,354	2,743,377	148,419,207	174,883,987
Top ten total as percent of PJM total	58.5%	59.3%	90.8%	42.6%	45.6%
PJM total as percent of all up to congestion transactions	5.8%	7.8%	1.6%	84.9%	100.0%
	2024				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	3,417,382	4,450,811	1,899,273	29,694,125	39,461,590
PJM total (MW)	6,716,121	7,235,170	2,052,939	78,630,949	94,635,178
Top ten total as percent of PJM total	50.9%	61.5%	92.5%	37.8%	41.7%
PJM total as percent of all up to congestion transactions	7.1%	7.6%	2.2%	83.1%	100.0%

69 See 162 FERC ¶ 61,139 (2018), *reh'g denied*, 164 FERC ¶ 61,170 (2018).
70 *Id.*
71 See 172 FERC ¶ 61,046 (2020).

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Figure 3-23 Monthly cleared up to congestion transactions by type (GWh): January 2005 through December 2024

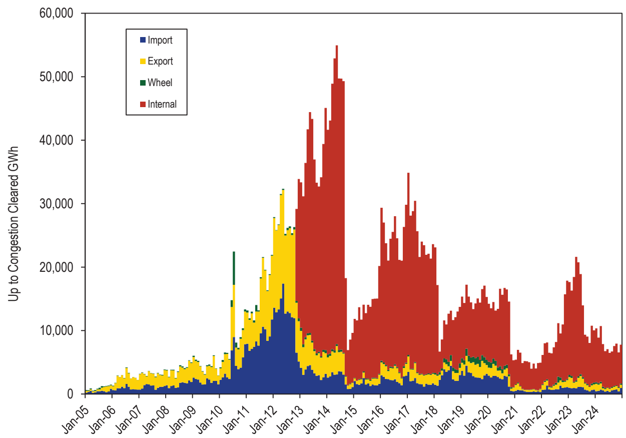
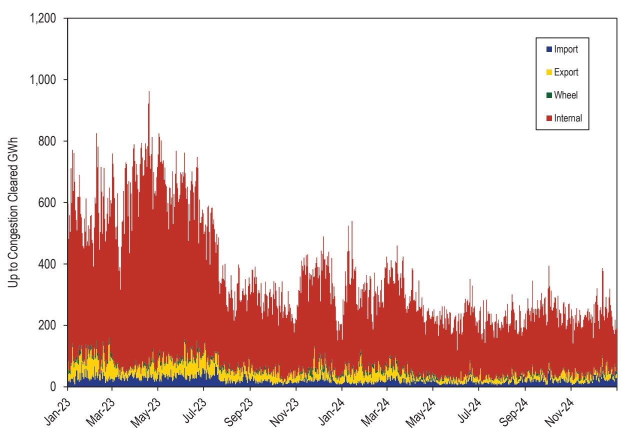


Figure 3-24 shows the daily cleared up to congestion GWh by transaction type from January 1, 2023, through December 31, 2024. In 2024, the total cleared GWh of import and export transactions remained relatively unchanged, while internal up to congestion transactions decreased significantly compared to 2023.

Figure 3-24 Daily cleared up to congestion transaction by type (GWh): January 2023 through December 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.[72]

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 of prices over a large number of buses at aggregate nodes.[73] This assumption is not correct, given the large share of INC, DEC, and UTC profits still attributable to modeling or operational differences between day-ahead and real-time 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 constraints are violated and transmission penalty factors are applied in the real-time energy market. Even when the same constraints are modeled in day ahead and real time, constraint violations in real time may result from differences in the day-ahead and real-time operational environments such as intra hourly ramping limitations, changes to constraint limits, and unit commitments and decommitments. Price spreads due to modeling or operational differences can be 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-

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

73 162 FERC ¶ 61,139 at PP 35–36 ("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.").

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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.

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 2024 increased $1.63 per MWh, or 5.5 percent from 2023, from $29.69 per MWh to $31.32 per MWh. The real-time load-weighted average LMP in 2024 increased $2.66 per MWh, or 8.5 percent from 2023, from $31.08 per MWh to $33.74 per MWh.

The costs of fuel, emissions, and consumables, fundamental components of the real-time load-weighted average LMP, increased $0.50 per MWh from $19.56 per MWh in 2023 to $20.06 per MWh in 2024, or 18.9 percent of the increase in real-time load-weighted average LMP.

The day-ahead average LMP for 2024 increased $1.03 per MWh, or 3.4 percent from 2023, from $30.38 per MWh to $31.41 per MWh. The day-ahead load-weighted average LMP for 2024 increased $1.86 or 5.8 percent from 2023, from $31.93 per MWh to $33.79 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.[74] In the nodal pricing system, the LMP at a pricing node is the total cost of meeting incremental demand at that node. When there are binding transmission constraints, satisfying the marginal increase in demand at a node may require increasing the output of some generators while simultaneously decreasing the output of other generators, such that the transmission constraints are not violated. The total cost of redispatching multiple generators can at times exceed the cost of marginally increasing the output of the most expensive generator offered. Thus, the LMPs at some pricing nodes exceed $1,000 per MWh, the cap on the generators' offer price in the PJM market.[75]

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. But 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.

74 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.

75 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).

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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 a new and incorrect LMP calculation called the pricing run. The pricing run LMP (PLMP) is now the official settlement LMP in PJM, replacing the dispatch run LMP (DLMP). Unless otherwise specified, the LMP tables and figures show the PLMP for September 1, 2021, and after.

The pricing run calculates LMP using the same optimal power flow algorithm as the dispatch run while simultaneously ignoring (relaxing) the economic minimum and maximum output MW constraints for all eligible fast start units. Fast start units must have notification time plus start time 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. This price calculation has not been reviewed by FERC or included in the PJM Operating Agreement. Every difference between the dispatch run and the pricing run introduces inefficiency in the market.

DLMP and PLMP

Table 3-32 shows the day-ahead and real-time monthly load-weighted average PLMP and DLMP in 2023 and 2024.

The real-time load-weighted average PLMP was $33.74 per MWh in 2024, which is 7.7 percent, $2.43 per MWh, higher than the real-time load-weighted average DLMP of $31.31 per MWh.

The day-ahead load-weighted average PLMP was $33.79 per MWh in 2024, which is 0.2 percent, $0.07 per MWh, higher than the day-ahead load-weighted average DLMP of $33.72 per MWh.

Table 3-32 Day-ahead and real-time load-weighted average DLMP and PLMP: 2023 through 2024

		Day-Ahead Load-Weighted Average				Real-Time Load-Weighted Average			
Year	Month	DLMP	PLMP	Difference	Percent Difference	DLMP	PLMP	Difference	Percent Difference
2023	Jan	$36.53	$36.58	$0.05	0.1%	$34.66	$35.75	$1.09	3.1%
2023	Feb	$31.16	$31.22	$0.06	0.2%	$25.47	$26.04	$0.57	2.2%
2023	Mar	$28.39	$28.41	$0.02	0.1%	$27.58	$28.42	$0.85	3.1%
2023	Apr	$29.81	$29.81	($0.00)	(0.0%)	$27.09	$29.32	$2.22	8.2%
2023	May	$28.86	$28.80	($0.05)	(0.2%)	$25.91	$28.44	$2.53	9.7%
2023	Jun	$27.82	$27.82	($0.00)	(0.0%)	$25.69	$27.29	$1.60	6.2%
2023	Jul	$40.46	$40.56	$0.10	0.3%	$34.34	$37.21	$2.87	8.4%
2023	Aug	$30.49	$30.54	$0.05	0.2%	$29.77	$31.33	$1.55	5.2%
2023	Sep	$30.82	$30.91	$0.09	0.3%	$29.33	$31.55	$2.22	7.6%
2023	Oct	$35.15	$35.17	$0.02	0.1%	$30.61	$34.77	$4.16	13.6%
2023	Nov	$33.32	$33.40	$0.08	0.2%	$30.40	$32.94	$2.54	8.3%
2023	Dec	$27.97	$28.00	$0.03	0.1%	$26.37	$27.97	$1.59	6.0%
2023		$31.89	$31.93	$0.04	0.1%	$29.11	$31.08	$1.97	6.8%
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		$33.72	$33.79	$0.07	0.2%	$31.31	$33.74	$2.43	7.7%

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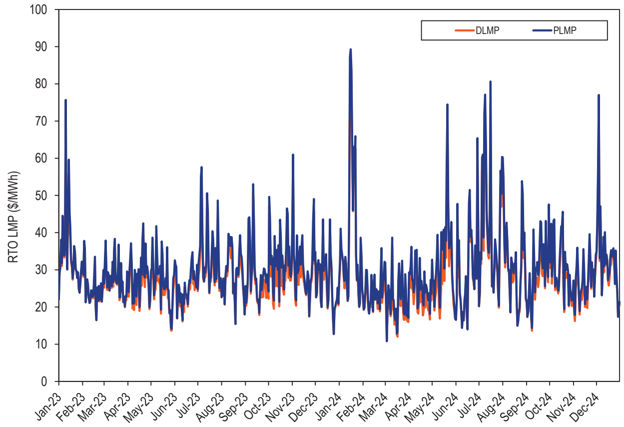
Figure 3-25 shows the real-time daily average DLMP and PLMP in 2023 through 2024.

Figure 3-25 Real-time daily average DLMP and PLMP: 2023 through 2024



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 2024. The big differences between DA DLMP and PLMP on January 13, 2024, and August 27, 2024, were caused by the larger 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.

Figure 3-26 Hourly difference between DLMP and PLMP for day-ahead and real-time: 2024

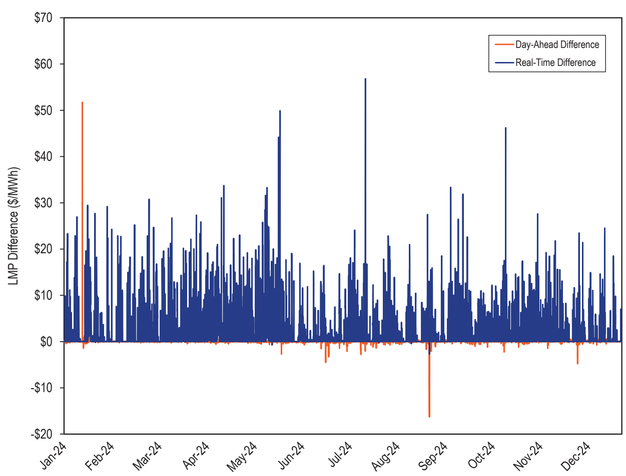


Figure 3-27 shows the hourly average load and LMP difference by hour of the day for 2024. The PLMP minus DLMP difference is largest at the times of the morning and evening peak loads.

Figure 3-27 Hourly average load and LMP difference: 2024

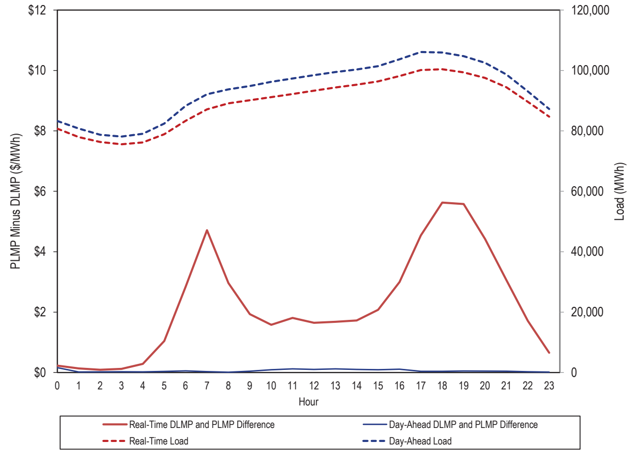


Table 3-33 shows the percent of total marginal units that are fast start units by unit type in 2023 and 2024. While wind units are defined as fast start units, a wind unit on the margin does not result in a higher PLMP than DLMP when the unit has no commitment costs.

Table 3-33 Fast start units as a percent of real-time marginal units: 2023 through 2024

		Dispatch Run				Pricing Run			
Year	Month	CT	Diesel	Wind	All Fast Start Units	CT	Diesel	Wind	All Fast Start Units
2023	Jan	1.6%	0.5%	0.1%	2.1%	6.2%	2.8%	0.0%	9.0%
2023	Feb	0.9%	0.2%	0.0%	1.1%	3.1%	0.6%	0.0%	3.7%
2023	Mar	0.8%	0.4%	0.1%	1.2%	3.0%	0.7%	0.1%	3.8%
2023	Apr	2.5%	0.4%	0.2%	3.2%	8.1%	0.8%	0.2%	9.1%
2023	May	1.0%	0.3%	0.1%	1.3%	4.8%	0.7%	0.1%	5.6%
2023	Jun	0.5%	0.2%	0.0%	0.7%	2.5%	0.5%	0.0%	3.0%
2023	Jul	1.4%	0.9%	0.0%	2.4%	8.6%	1.6%	0.0%	10.3%
2023	Aug	0.9%	1.5%	0.0%	2.4%	5.1%	2.3%	0.0%	7.4%
2023	Sep	0.4%	0.8%	0.1%	1.3%	5.1%	1.4%	0.1%	6.6%
2023	Oct	1.4%	0.3%	0.0%	1.7%	6.9%	0.8%	0.0%	7.7%
2023	Nov	4.0%	0.6%	0.0%	4.5%	11.4%	1.4%	0.0%	12.8%
2023	Dec	1.4%	0.7%	0.0%	2.2%	7.2%	2.0%	0.0%	9.3%
2023		1.4%	0.6%	0.0%	2.0%	6.0%	1.3%	0.0%	7.4%
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		0.8%	0.3%	0.2%	1.2%	4.9%	0.7%	0.2%	5.8%

Table 3-34 shows the difference between day-ahead and real-time zonal average DLMP and PLMP for 2024.

Fast start pricing affects some zones more than others. The average difference in real-time prices in BGE was $2.93 per MWh, while the average difference in real-time prices in PECO was $1.56 per MWh.

Table 3-34 Day-ahead and real-time zonal average DLMP and PLMP (Dollars per MWh): 2024

	2024							
	Day-Ahead				Real-Time			
Zone	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
ACEC	$27.49	$27.54	$0.05	0.2%	$25.90	$27.52	$1.62	6.3%
AEP	$31.12	$31.18	$0.06	0.2%	$29.05	$31.35	$2.31	7.9%
APS	$32.27	$32.33	$0.06	0.2%	$29.80	$32.18	$2.38	8.0%
ATSI	$31.46	$31.47	$0.01	0.0%	$29.08	$31.32	$2.24	7.7%
BGE	$40.03	$40.11	$0.08	0.2%	$36.60	$39.53	$2.93	8.0%
COMED	$25.48	$25.55	$0.07	0.3%	$23.28	$25.22	$1.94	8.3%
DAY	$32.62	$32.69	$0.06	0.2%	$30.30	$32.75	$2.46	8.1%
DUKE	$31.22	$31.28	$0.06	0.2%	$28.90	$31.21	$2.31	8.0%
DOM	$36.96	$37.02	$0.06	0.2%	$33.54	$36.15	$2.61	7.8%
DPL	$31.27	$31.36	$0.09	0.3%	$28.44	$30.94	$2.50	8.8%
DUQ	$30.93	$30.97	$0.04	0.1%	$29.02	$31.23	$2.21	7.6%
EKPC	$30.58	$30.64	$0.06	0.2%	$28.57	$30.84	$2.27	8.0%
JCPLC	$27.52	$27.57	$0.06	0.2%	$26.00	$27.67	$1.67	6.4%
MEC	$28.66	$28.71	$0.06	0.2%	$26.28	$28.15	$1.87	7.1%
OVEC	$29.88	$29.93	$0.06	0.2%	$27.73	$29.94	$2.20	7.9%
PECO	$27.11	$27.17	$0.05	0.2%	$25.56	$27.12	$1.56	6.1%
PE	$32.06	$32.10	$0.04	0.1%	$29.46	$31.61	$2.15	7.3%
PEPCO	$38.11	$38.18	$0.07	0.2%	$34.85	$37.61	$2.76	7.9%
PPL	$26.76	$26.82	$0.06	0.2%	$24.86	$26.58	$1.72	6.9%
PSEG	$27.78	$27.83	$0.06	0.2%	$26.33	$28.02	$1.69	6.4%
REC	$30.13	$30.18	$0.05	0.2%	$28.14	$29.93	$1.79	6.4%

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Table 3-35 shows the difference between day-ahead and real-time average DLMP and PLMP for PJM hubs for 2024.

The average difference in real-time prices for the DOMINION HUB was $2.50 per MWh, while the average difference in real-time prices for the NEW JERSEY HUB was $1.67 per MWh.

Table 3-35 Day-ahead and real-time average DLMP and PLMP for PJM hubs (Dollars per MWh): 2024

	2024							
	Day-Ahead				Real-Time			
Hub	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
AEP GEN HUB	$29.76	$29.79	$0.04	0.1%	$27.69	$29.92	$2.23	8.1%
AEP-DAYTON HUB	$30.70	$30.73	$0.03	0.1%	$28.42	$30.69	$2.27	8.0%
ATSI GEN HUB	$30.99	$31.01	$0.02	0.1%	$28.32	$30.50	$2.18	7.7%
CHICAGO GEN HUB	$24.78	$24.88	$0.09	0.4%	$22.31	$24.29	$1.98	8.9%
CHICAGO HUB	$25.75	$25.77	$0.02	0.1%	$23.49	$25.44	$1.95	8.3%
DOMINION HUB	$34.03	$34.07	$0.04	0.1%	$31.26	$33.76	$2.50	8.0%
EASTERN HUB	$31.23	$31.28	$0.05	0.2%	$28.30	$30.79	$2.48	8.8%
N ILLINOIS HUB	$25.36	$25.46	$0.11	0.4%	$23.30	$25.23	$1.94	8.3%
NEW JERSEY HUB	$27.65	$27.68	$0.03	0.1%	$26.11	$27.79	$1.67	6.4%
OHIO HUB	$30.66	$30.69	$0.03	0.1%	$28.36	$30.62	$2.26	8.0%
WEST INT HUB	$32.17	$32.19	$0.02	0.1%	$29.80	$32.15	$2.35	7.9%
WESTERN HUB	$33.80	$33.83	$0.03	0.1%	$30.84	$33.24	$2.40	7.8%

Table 3-36 shows the frequency of the real-time pricing interval differences in DLMP and PLMP by price range for PJM zones for 2024.

Table 3-36 Frequency of real-time interval difference (dollars per MWh) between zonal DLMP and PLMP: 2024

	2024									
Zone	< ($50)	($50) to ($10)	($10) to $0	$0	$0 to $10	$10 to $20	$20 to $50	$50 to $100	$100 to $200	>= $200
PJM-RTO	0.0%	0.0%	0.7%	52.2%	40.3%	4.7%	1.9%	0.1%	0.0%	0.0%
ACEC	0.0%	0.0%	4.4%	52.4%	38.5%	3.2%	1.4%	0.1%	0.0%	0.0%
AEP	0.0%	0.0%	1.4%	52.4%	39.1%	4.9%	2.1%	0.1%	0.0%	0.0%
APS	0.0%	0.0%	1.1%	52.3%	39.2%	4.9%	2.3%	0.1%	0.0%	0.0%
ATSI	0.0%	0.1%	1.8%	52.3%	39.0%	4.7%	2.1%	0.1%	0.0%	0.0%
BGE	0.0%	0.1%	2.4%	52.2%	36.0%	5.5%	3.3%	0.4%	0.1%	0.0%
COMED	0.0%	0.1%	3.6%	53.3%	37.1%	4.1%	1.7%	0.1%	0.0%	0.0%
DAY	0.0%	0.0%	1.4%	52.4%	38.4%	5.1%	2.5%	0.1%	0.0%	0.0%
DUKE	0.0%	0.0%	1.5%	52.4%	38.9%	4.9%	2.1%	0.1%	0.0%	0.0%
DOM	0.0%	0.1%	1.7%	52.3%	37.7%	5.2%	2.7%	0.2%	0.0%	0.0%
DPL	0.0%	0.1%	6.3%	52.4%	34.9%	3.1%	2.5%	0.4%	0.3%	0.0%
DUQ	0.0%	0.0%	1.5%	52.3%	39.3%	4.6%	2.0%	0.1%	0.0%	0.0%
EKPC	0.0%	0.0%	1.4%	52.4%	39.3%	4.8%	2.0%	0.1%	0.0%	0.0%
JCPLC	0.0%	0.0%	2.3%	52.5%	40.6%	3.2%	1.4%	0.1%	0.0%	0.0%
MEC	0.0%	0.1%	3.7%	52.3%	38.3%	3.8%	1.6%	0.1%	0.0%	0.0%
OVEC	0.0%	0.1%	1.6%	52.4%	39.0%	4.7%	2.0%	0.1%	0.0%	0.0%
PECO	0.0%	0.1%	5.9%	52.4%	37.1%	3.1%	1.4%	0.1%	0.0%	0.0%
PE	0.0%	0.0%	1.5%	52.1%	39.9%	4.5%	1.9%	0.1%	0.0%	0.0%
PEPCO	0.0%	0.1%	2.1%	52.3%	36.8%	5.4%	3.0%	0.3%	0.0%	0.0%
PPL	0.0%	0.1%	3.1%	52.3%	39.7%	3.4%	1.4%	0.1%	0.0%	0.0%
PSEG	0.0%	0.0%	2.2%	52.4%	40.7%	3.2%	1.4%	0.1%	0.0%	0.0%
REC	0.0%	0.1%	2.1%	52.2%	40.7%	3.3%	1.5%	0.1%	0.0%	0.0%

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Real-Time Average LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[76]

PJM Real-Time Average LMP

Table 3-37 shows the real-time average LMP for 1998 through 2024.[77] The real-time average LMP in 2024 increased $1.63 per MWh, or 5.5 percent from 2023, from $29.69 per MWh to $31.32 per MWh.

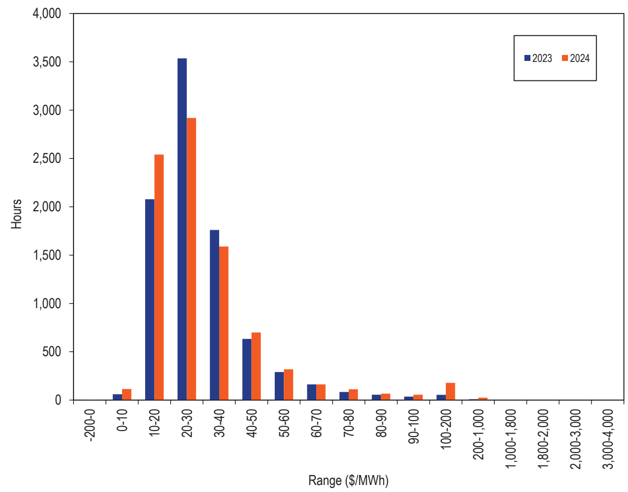
Table 3-37 Real-time average LMP (Dollars per MWh): 1998 through 2024

	Real-Time LMP			Year to Year Change			
	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA	NA
1999	$28.32	$17.88	$72.42	$6.60	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	($0.18)	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	$4.24	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	($4.08)	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	$9.98	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	$4.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	$15.68	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	($8.81)	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	$8.30	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	$8.82	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	($29.31)	(44.1%)	(41.1%)	(55.7%)
2010	$44.83	$36.88	$26.20	$7.75	20.9%	12.7%	53.1%
2011	$42.84	$35.38	$29.03	($1.99)	(4.4%)	(4.1%)	10.8%
2012	$33.11	$29.53	$20.67	($9.73)	(22.7%)	(16.5%)	(28.8%)
2013	$36.55	$32.25	$20.57	$3.44	10.4%	9.2%	(0.5%)
2014	$48.22	$34.46	$65.08	$11.67	31.9%	6.8%	216.4%
2015	$33.39	$26.61	$27.80	($14.82)	(30.7%)	(22.8%)	(57.3%)
2016	$27.57	$24.10	$14.76	($5.82)	(17.4%)	(9.4%)	(46.9%)
2017	$29.42	$25.44	$17.40	$1.85	6.7%	5.6%	17.9%
2018	$35.75	$28.28	$29.52	$6.33	21.5%	11.2%	69.7%
2019	$26.02	$22.89	$21.19	($9.73)	(27.2%)	(19.1%)	(28.2%)
2020	$20.66	$18.35	$11.77	($5.36)	(20.6%)	(19.8%)	(44.4%)
2021	$38.18	$30.59	$26.37	$17.52	84.8%	66.7%	124.0%
2022	$73.53	$57.13	$115.77	$35.35	92.6%	86.8%	339.1%
2023	$29.69	$25.80	$18.42	($43.84)	(59.6%)	(54.8%)	(84.1%)
2024	$31.32	$25.37	$24.84	$1.63	5.5%	(1.7%)	34.9%

PJM Real-Time Average LMP Duration

Figure 3-28 shows the hourly distribution of the real-time average LMP in 2023 and 2024. In 2023, the most common price range was $20 to $30 per MWh. In 2024, the most common price range was also $20 to $30 per MWh.

Figure 3-28 Distribution of real-time LMP: 2023 and 2024



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 3-38 shows the real-time load-weighted average LMP for 1998 through 2024. The real-time load-weighted average LMP in 2024 increased $2.66 per MWh, or 8.5 percent from 2023, from $31.08 per MWh to $33.74 per MWh.

76 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>.

77 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.

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Table 3-38 Real-time load-weighted average LMP (Dollars per MWh): 1998 through 2024

	Real-Time Load-Weighted Average LMP			Year to Year Change			
	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA	NA
1999	$34.07	$19.02	$91.49	$9.91	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	($3.34)	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	$5.93	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	($5.06)	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	$9.64	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	$3.10	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	$19.12	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	($10.11)	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	$8.31	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	$9.47	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	($32.09)	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	$9.30	23.8%	14.3%	58.7%
2011	$45.94	$36.54	$33.47	($2.41)	(5.0%)	(6.6%)	15.8%
2012	$35.23	$30.43	$23.66	($10.71)	(23.3%)	(16.7%)	(29.3%)
2013	$38.66	$33.25	$23.78	$3.43	9.7%	9.3%	0.5%
2014	$53.14	$36.20	$76.20	$14.47	37.4%	8.9%	220.4%
2015	$36.16	$27.66	$31.06	($16.98)	(31.9%)	(23.6%)	(59.2%)
2016	$29.23	$25.01	$16.12	($6.93)	(19.2%)	(9.6%)	(48.1%)
2017	$30.99	$26.35	$19.32	$1.76	6.0%	5.4%	19.9%
2018	$38.24	$29.55	$32.89	$7.25	23.4%	12.1%	70.2%
2019	$27.32	$23.63	$23.12	($10.92)	(28.6%)	(20.0%)	(29.7%)
2020	$21.77	$19.07	$12.50	($5.55)	(20.3%)	(19.3%)	(45.9%)
2021	$39.78	$32.11	$27.72	$18.02	82.8%	68.4%	121.8%
2022	$80.14	$60.09	$135.55	$40.36	101.4%	87.2%	389.1%
2023	$31.08	$26.83	$19.77	($49.06)	(61.2%)	(55.3%)	(85.4%)
2024	$33.74	$26.85	$27.54	$2.66	8.5%	0.1%	39.3%

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 2024.

Figure 3-29 Real-time monthly and yearly load-weighted average LMP: 1999 through 2024

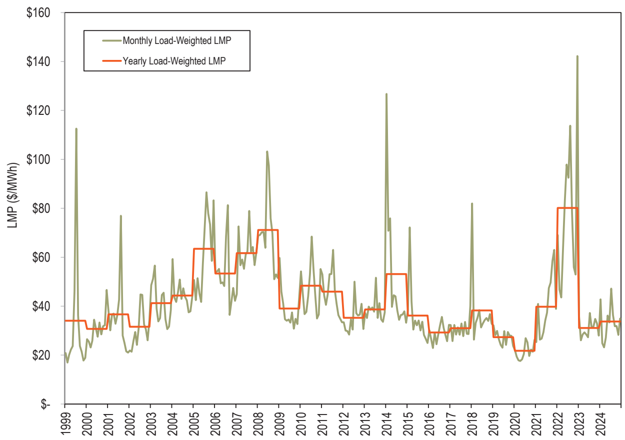


Table 3-39 shows the real-time monthly on peak and off peak load-weighted average LMP for 2023 through 2024.

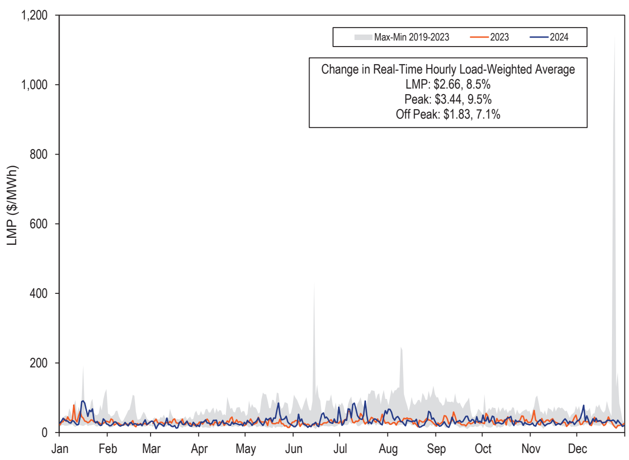
Table 3-39 Real-time monthly on peak and off peak load-weighted average LMP (Dollars per MWh): 2023 through 2024

	2023				2024			
	Off Peak	On Peak	Difference	Percent Difference	Off Peak	On Peak	Difference	Percent Difference
Jan	$33.20	$38.53	$5.32	16.0%	$38.50	$47.10	$8.60	22.3%
Feb	$23.45	$28.67	$5.22	22.3%	$24.49	$25.23	$0.74	3.0%
Mar	$26.96	$29.78	$2.82	10.5%	$21.64	$24.79	$3.15	14.6%
Apr	$24.08	$35.00	$10.92	45.4%	$23.99	$30.03	$6.04	25.2%
May	$22.65	$33.84	$11.19	49.4%	$28.99	$42.74	$13.75	47.4%
Jun	$21.64	$32.16	$10.52	48.6%	$26.66	$40.04	$13.38	50.2%
Jul	$26.86	$48.04	$21.18	78.9%	$32.20	$60.78	$28.58	88.7%
Aug	$26.68	$35.31	$8.63	32.3%	$26.71	$44.99	$18.28	68.5%
Sep	$24.76	$38.65	$13.88	56.1%	$24.53	$39.42	$14.89	60.7%
Oct	$26.41	$42.58	$16.17	61.2%	$26.60	$36.49	$9.89	37.2%
Nov	$29.72	$37.01	$7.29	24.5%	$23.80	$33.18	$9.38	39.4%
Dec	$23.70	$32.88	$9.18	38.7%	$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 2023 through 2024.

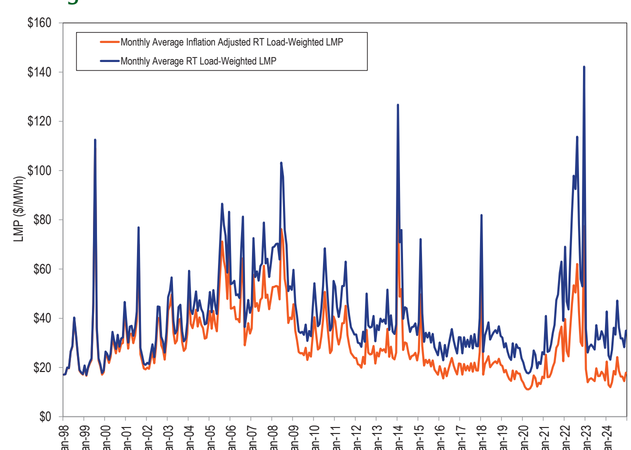
Figure 3-30 Real-time daily load-weighted average LMP: 2023 through 2024



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 December 2024.[78] Table 3-40 shows the PJM real-time load-weighted average LMP and inflation adjusted load-weighted average LMP for every year from 1998 through 2024.

Figure 3-31 Real-time monthly load-weighted average LMP unadjusted and adjusted for inflation: 1998 through 2024



78 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 January 15, 2025)

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Table 3-40 Real-time load-weighted and inflation adjusted load-weighted average LMP: 1998 through 2024

	Load-Weighted Average LMP	Inflation Adjusted Load-Weighted Average LMP
1998	$24.16	$23.94
1999	$34.07	$33.04
2000	$30.72	$28.80
2001	$36.65	$33.45
2002	$31.60	$28.35
2003	$41.23	$36.24
2004	$44.34	$37.91
2005	$63.46	$52.37
2006	$53.35	$42.73
2007	$61.66	$48.06
2008	$71.13	$53.27
2009	$39.05	$29.46
2010	$48.35	$35.83
2011	$45.94	$33.01
2012	$35.23	$24.80
2013	$38.66	$26.82
2014	$53.14	$36.37
2015	$36.16	$24.69
2016	$29.23	$19.68
2017	$30.99	$20.43
2018	$38.24	$24.65
2019	$27.32	$17.28
2020	$21.77	$13.58
2021	$39.78	$23.63
2022	$80.14	$44.12
2023	$31.08	$16.48
2024	$33.74	$17.38

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).[79] 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. In 2021, 2022, 2023, and 2024, on average, PJM operators approved one RT SCED solution per five minute target time to send dispatch signals to resources. PJM uses a subset of these approved RT SCED solutions in LPC to calculate real-time LMPs every five minutes. Prior to October 15, 2020, LPC used the latest available approved RT SCED solution to calculate prices, regardless of the target dispatch time of the RT SCED solution, but LPC assigned the prices to a five minute interval that did not contain the target time of the RT SCED case it used. On October 15, 2020, PJM updated its pricing process to use an approved RT SCED solution that solves for the same target time as the end of each five minute pricing interval to calculate LMPs applicable for that five minute interval, although the SCED cases were still for 10 minutes ahead while the LPC cases were for each five minute interval. As a result, under the default timing of case approvals, resources followed the dispatch signal in the first five minutes after the RT SCED case approval and the corresponding pricing occurred five minutes after the same case approval, when resources were following a new dispatch signal. On November 1, 2021, PJM implemented changes to RT SCED that solved the energy dispatch case using a five-minute dispatch period, and ramped resources for five minutes to meet the load and reserve requirements at the end of each five minute period. The approved RT SCED solution that dispatched units for each five minute period was also used to calculate prices for the same five minute interval, aligning the prices with the dispatch signals.

Table 3-41 shows the number of RT SCED case solutions, the number of solutions that were approved, and the number and percent of approved solutions used in LPC. The RT SCED execution frequency is once every five minutes. PJM operators have the ability to execute additional RT SCED cases. Each execution of RT SCED produces five solutions, using five different levels of load bias. Since prices are calculated every five minutes while five SCED solutions are produced every five minutes, there is, by definition, a larger number of SCED solutions than there are five minute intervals in any given period.

Table 3-41 shows that in 2024, 97.2 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 97.6 percent in all of 2023.

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

Table 3-41 RT SCED cases solved, approved and used in pricing: 2023 through 2024

	2023				2024			
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	45,175	9,075	8,900	98.1%	45,594	9,161	8,891	97.1%
Feb	40,924	8,225	7,987	97.1%	43,066	8,659	8,288	95.7%
Mar	44,876	9,016	8,861	98.3%	45,340	8,972	8,845	98.6%
Apr	43,823	8,761	8,563	97.7%	44,365	8,767	8,606	98.2%
May	46,378	8,994	8,808	97.9%	46,149	9,177	8,853	96.5%
Jun	44,228	8,800	8,598	97.7%	44,464	8,841	8,598	97.3%
Jul	45,809	9,202	8,916	96.9%	45,629	9,138	8,881	97.2%
Aug	45,498	9,047	8,779	97.0%	45,616	9,192	8,894	96.8%
Sep	44,325	8,794	8,607	97.9%	44,275	8,752	8,550	97.7%
Oct	45,804	9,065	8,850	97.6%	45,806	9,144	8,879	97.1%
Nov	44,284	8,842	8,607	97.3%	44,055	8,850	8,607	97.3%
Dec	45,359	9,059	8,885	98.1%	45,460	9,120	8,899	97.6%
Total	536,483	106,880	104,361	97.6%	539,819	107,773	104,791	97.2%

Until November 1, 2021, PJM did not link dispatch and settlement intervals. RT SCED moved from automatically executing a case every three minutes to every five minutes in 2020, while settlements are linked to five minute intervals. Until November 1, 2021, RT SCED solved the dispatch problem for a target time that was generally 14 minutes in the future. An RT SCED case was approved and sent dispatch signals to generators based on a 10 minute ramp time. The look ahead time for the load forecast and the look ahead time for the resource dispatch target did not match, and a new RT SCED case would override the previously approved case before resources had time to achieve the previous target dispatch. Prior to October 15, 2020, the interval that was priced in LPC was consistently before the target time from the RT SCED case used for the dispatch signal. LPC took the most recently approved RT SCED case to calculate LMPs for the present five minute interval. For example, the LPC case that calculated prices for the interval ending 10:05 EPT used an approved RT SCED case that sent MW dispatch signals for the target time of 10:10 EPT. This discrepancy created a mismatch between the MW dispatch and real-time LMPs and undermined generators' incentive to follow dispatch. Under new RT SCED changes that were implemented on October 15, 2020, PJM resolved the mismatch between LPC and the RT SCED target time, but prices no longer applied at the time when resources received and followed that dispatch signal.[80] For example, the LPC case that calculated prices for the interval ending 10:05 EPT used an approved RT SCED case that sent MW dispatch signals at 9:55 EPT which were no longer effective from 10:00 to 10:05 EPT.

In the first 10 months of 2021, there was a mismatch between the MW dispatch and real-time LMPs that undermined generators' incentive to follow dispatch. The timing remained incorrect until all three (the pricing interval, the dispatch interval, and the RT SCED target time) all corresponded to one another, which PJM implemented on November 1, 2021.

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

80 See Docket No. ER19-2573-000.

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Table 3-42 shows the average duration of the period when dispatch instructions corresponded to the prevailing prices. Prior to October 15, 2020, PJM used the latest approved RT SCED solution available at the time of LPC execution, regardless of the SCED target time, to calculate prices for the current five minute pricing interval. The average duration of correspondence ranged from 3 minutes 11 seconds to 3 minutes 37 seconds from January through October 15, 2020, varying with changes to the frequency of automatic RT SCED execution. The percent of time that prices were consistent with the dispatch instructions was 67.2 to 69.9 percent, on average. This was far from the goal of 100 percent correspondence between five minute dispatch instructions and prices. With the short term changes to RT SCED that were implemented on October 15, 2020, the prices no longer corresponded to the dispatch instructions. Table 3-42 shows that during the first 10 months of 2021, the dispatch instructions were consistent with prevailing prices for only 33 seconds. During this period, the percent of time that prices were consistent with the dispatch instructions was 9.0 percent. In the period beginning November 1, 2021, PJM aligned the dispatch and pricing intervals such that the prices that were effective for each five minute interval were generally based on the RT SCED case that sent dispatch signals with the target time at the end of the five minute interval. As a result of these changes, in 2022, the dispatch instructions were consistent with the prices on average for 4 minutes and 45 seconds out of each five minute interval, or 95.7 percent of each five minute interval. In 2023, the dispatch instructions were consistent with prices on average for 4 minutes and 47 seconds out of each five minute interval, or 95.9 percent of each five minute interval. In 2024, the dispatch instructions were consistent with prices on average for 4 minutes and 46 seconds out of each five minute interval, or 96.0 percent of each five minute interval.

Table 3-42 Dispatch instructions reflected in prices: 2020 through 2024

Period	RT SCED Automatic Execution Frequency	Dispatch Duration Reflected in Prices (Minutes:Seconds)	Percent Dispatch Duration Reflected in Prices
Jan 1, 2020 - Feb 23, 2020	Every 3 minutes	03:11	67.9%
Feb 24, 2020 - Jun 22, 2020	Every 4 minutes	03:27	67.2%
Jun 23, 2020 - Oct 14, 2020	Every 5 minutes	03:37	69.9%
Oct 15, 2020 - Dec 31, 2020	Every 5 minutes	00:39	9.9%
Jan 1, 2021 - Oct 31, 2021	Every 5 minutes	00:33	9.0%
Nov 1, 2021 - Dec 31, 2021	Every 5 minutes	04:46	95.4%
Jan 1, 2022 - Dec 31, 2022	Every 5 minutes	04:45	95.6%
Jan 1, 2023 - Dec 31, 2023	Every 5 minutes	04:47	95.9%
Jan 1, 2024 - Dec 31, 2024	Every 5 minutes	04:46	96.0%

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.[81] Table 3-43 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 2023 and 2024. In 2024, PJM recalculated LMPs for 2,359 five minute intervals or 2.24 percent of the total 105,408 five minute intervals.

Table 3-43 Number of five minute interval real-time prices recalculated: January 2023 through December 2024

	2023		2024	
Month	Number of Five Minute Intervals	Number of Five Minute Intervals for Which LMPs Were Recalculated	Number of Five Minute Intervals	Number of Five Minute Intervals for Which LMPs Were Recalculated
January	8,928	161	8,928	164
February	8,064	166	8,352	285
March	8,916	123	8,916	304
April	8,640	234	8,640	154
May	8,928	337	8,928	193
June	8,640	165	8,640	167
July	8,928	229	8,928	274
August	8,928	615	8,928	171
September	8,640	175	8,640	167
October	8,928	332	8,928	155
November	8,652	143	8,652	160
December	8,928	118	8,928	165
Total	105,120	2,798	105,408	2,359

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

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Day-Ahead Average LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[82]

PJM Day-Ahead Average LMP

Table 3-44 shows the day-ahead average LMP for 2001 through 2024. The day-ahead average LMP for 2024 increased $1.03 per MWh, or 3.4 percent from 2023, from $30.38 per MWh to $31.41 per MWh.

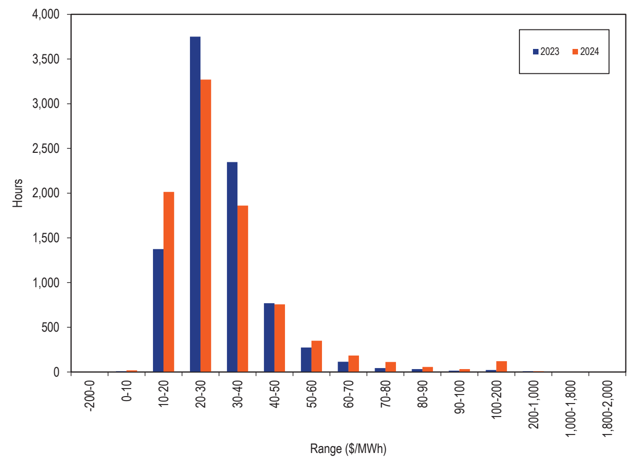
Table 3-44 Day-ahead average LMP (Dollars per MWh): 2001 to 2024

	Day-Ahead LMP			Year to Year Change			
	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
2001	$32.75	$27.05	$30.42	NA	NA	NA	NA
2002	$28.46	$23.28	$17.68	($4.29)	(13.1%)	(14.0%)	(41.9%)
2003	$38.73	$35.22	$20.84	$10.27	36.1%	51.3%	17.8%
2004	$41.43	$40.36	$16.60	$2.70	7.0%	14.6%	(20.4%)
2005	$57.89	$50.08	$30.04	$16.47	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	($9.80)	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	$6.58	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	$11.44	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	($29.12)	(44.0%)	(40.3%)	(56.6%)
2010	$44.57	$39.97	$18.83	$7.57	20.5%	13.7%	40.6%
2011	$42.52	$38.13	$20.48	($2.05)	(4.6%)	(4.6%)	8.8%
2012	$32.79	$30.89	$13.27	($9.73)	(22.9%)	(19.0%)	(35.2%)
2013	$37.15	$34.63	$15.46	$4.35	13.3%	12.1%	16.5%
2014	$49.15	$38.10	$51.88	$12.00	32.3%	10.0%	235.6%
2015	$34.12	$29.09	$22.59	($15.03)	(30.6%)	(23.7%)	(56.5%)
2016	$28.10	$25.76	$10.68	($6.02)	(17.7%)	(11.4%)	(52.7%)
2017	$29.48	$26.94	$11.69	$1.38	4.9%	4.6%	9.5%
2018	$35.69	$30.96	$22.32	$6.21	21.1%	14.9%	91.0%
2019	$26.03	$24.36	$9.35	($9.66)	(27.1%)	(21.3%)	(58.1%)
2020	$20.33	$18.99	$7.00	($5.70)	(21.9%)	(22.0%)	(25.2%)
2021	$37.76	$32.15	$18.49	$17.43	85.8%	69.3%	164.3%
2022	$70.77	$61.13	$37.79	$33.01	87.4%	90.1%	104.4%
2023	$30.38	$27.98	$14.60	($40.39)	(57.1%)	(54.2%)	(61.4%)
2024	$31.41	$26.76	$19.40	$1.03	3.4%	(4.4%)	32.8%

PJM Day-Ahead Average LMP Duration

Figure 3-32 shows the hourly distribution of the day-ahead average LMP for 2023 and 2024.

Figure 3-32 Distribution of day-ahead LMP: 2023 and 2024



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.

82 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>.

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PJM Day-Ahead Load-Weighted Average LMP

Table 3-45 shows the day-ahead load-weighted average LMP for 2001 through 2024. The day-ahead load-weighted average LMP for 2024 increased $1.86 or 5.8 percent from 2023, from $31.93 per MWh to $33.79 per MWh.

Table 3-45 Day-ahead load-weighted average LMP (Dollars per MWh): 2001 to 2024

	Day-Ahead Load-Weighted Average LMP			Year to Year Change			
	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
2001	$36.01	$29.02	$37.48	NA	NA	NA	NA
2002	$31.80	$26.00	$20.68	($4.21)	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	$9.63	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	$1.44	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	$19.62	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	($11.16)	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	$6.55	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	$12.37	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	($31.43)	(44.7%)	(41.7%)	(57.7%)
2010	$47.65	$42.06	$20.59	$8.83	22.7%	14.7%	46.8%
2011	$45.19	$39.66	$24.05	($2.46)	(5.2%)	(5.7%)	16.8%
2012	$34.55	$31.84	$15.48	($10.64)	(23.5%)	(19.7%)	(35.6%)
2013	$38.93	$35.77	$18.05	$4.37	12.7%	12.3%	16.6%
2014	$53.62	$39.84	$59.62	$14.70	37.8%	11.4%	230.4%
2015	$36.73	$30.60	$25.46	($16.89)	(31.5%)	(23.2%)	(57.3%)
2016	$29.68	$27.00	$11.64	($7.05)	(19.2%)	(11.8%)	(54.3%)
2017	$30.85	$28.21	$12.64	$1.17	3.9%	4.5%	8.6%
2018	$37.97	$32.49	$24.76	$7.13	23.1%	15.2%	95.9%
2019	$27.23	$25.28	$10.18	($10.74)	(28.3%)	(22.2%)	(58.9%)
2020	$21.40	$19.78	$7.59	($5.83)	(21.4%)	(21.7%)	(25.5%)
2021	$39.37	$33.72	$19.30	$17.97	84.0%	70.5%	154.3%
2022	$75.44	$64.13	$41.25	$36.07	91.6%	90.2%	113.8%
2023	$31.93	$29.04	$16.64	($43.51)	(57.7%)	(54.7%)	(59.7%)
2024	$33.79	$28.37	$21.75	$1.86	5.8%	(2.3%)	30.7%

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 2024.

Figure 3-33 Day-ahead monthly and yearly load-weighted average LMP: 2001 through 2024

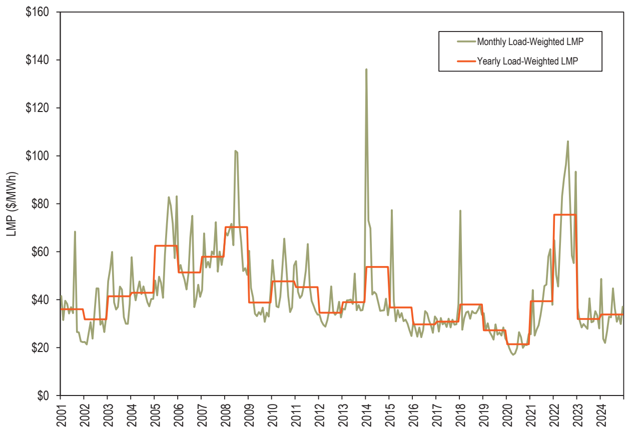
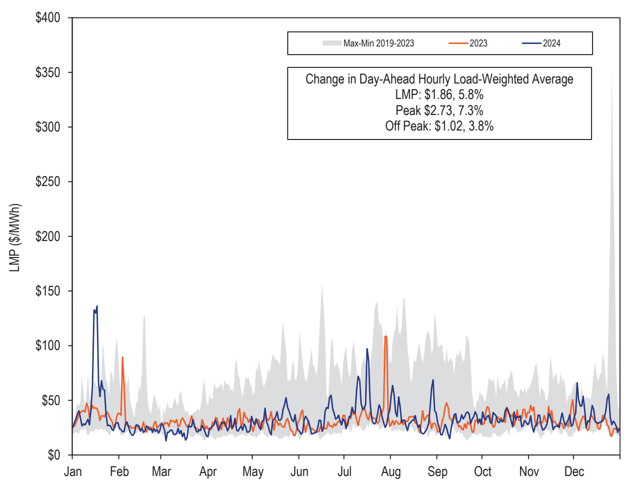


Figure 3-34 shows the day-ahead daily load-weighted average LMP in 2023 through 2024 compared to the historic five year price range.

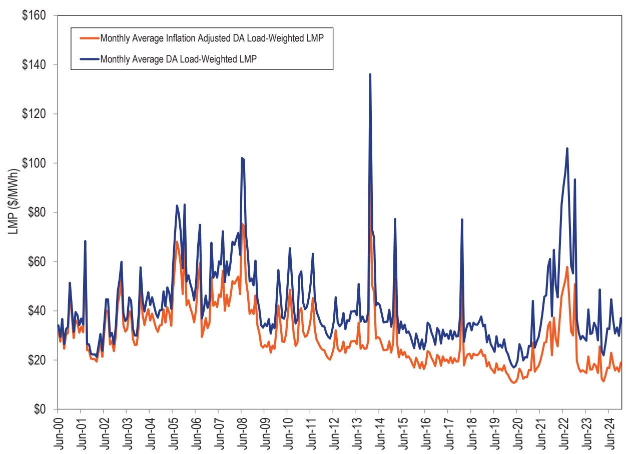
Figure 3-34 Day-ahead daily load-weighted average LMP: 2023 through 2024



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 December 2024.[83] Table 3-46 shows the PJM day-ahead load-weighted average LMP and inflation adjusted load-weighted average LMP for every year from 2000 through 2024.

Figure 3-35 Day-ahead monthly load-weighted and inflation adjusted load-weighted average LMP: June 2000 through December 2024



83 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed October 10, 2024).

Table 3-46 Day-ahead yearly load-weighted and inflation adjusted load-weighted average LMP: 2000 through 2024

	Load-Weighted Average LMP	Inflation Adjusted Load-Weighted Average LMP
2000	$35.13	$32.74
2001	$36.01	$32.87
2002	$31.80	$28.53
2003	$41.43	$36.42
2004	$42.87	$36.65
2005	$62.50	$51.58
2006	$51.33	$41.12
2007	$57.88	$45.11
2008	$70.25	$52.61
2009	$38.82	$29.29
2010	$47.65	$35.32
2011	$45.19	$32.48
2012	$34.55	$24.33
2013	$38.93	$27.00
2014	$53.62	$36.71
2015	$36.73	$25.08
2016	$29.68	$19.98
2017	$30.85	$20.34
2018	$37.97	$24.47
2019	$27.23	$17.23
2020	$21.40	$13.35
2021	$39.37	$23.40
2022	$75.44	$41.56
2023	$31.93	$16.93
2024	$33.79	$17.41

Price Convergence

The introduction of the PJM Day-Ahead Energy Market with virtuals as part of the design created the possibility that competition, exercised through the use of virtual offers and bids, could tend to cause prices in the day-ahead and real-time energy markets to converge more than would be the case without virtuals. Convergence is not the goal of virtual trading, but it is a possible outcome.

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

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

Where arbitrage incentives are created by systematic modeling differences, such as differences between the day-ahead and real-time modeled transmission

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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.[84]

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 3-47 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 2023 and 2024. In 2024, 40.2 percent of all cleared UTC transactions were profitable. Of cleared UTC transactions, 62.6 percent were profitable on the source side and 35.7 percent were profitable on the sink side, but only 7.7 percent were profitable on both the source and sink side.

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

Table 3-47 Cleared UTCs with positive profits at source and sink points: 2023 and 2024[85]

	Number of Cleared UTCs	Number of Profitable UTCs	Profitable at Source	Profitable at Sink	Profitable at Source and Sink	Share Profitable Overall	Share Profitable Source	Share Profitable Sink	Share Profitable Source and Sink
2023	7,691,139	3,212,091	5,059,265	2,587,293	541,139	41.8%	65.8%	33.6%	7.0%
2024	5,925,275	2,379,177	3,710,809	2,115,830	453,990	40.2%	62.6%	35.7%	7.7%

Table 3-48 shows the number of cleared INC and DEC transactions and the number of profitable transactions in 2023 and 2024. Of cleared INC and DEC transactions in 2024, 52.6 percent of INCs were profitable and 31.4 percent of DECs were profitable.

Table 3-48 Cleared INC and DEC transactions with positive profits: 2023 and 2024

	Cleared INC	Profitable INC	Profitable INC Share	Cleared DEC	Profitable DEC	Profitable DEC Share
2023	3,297,664	2,103,051	63.8%	2,838,502	994,688	35.0%
2024	3,844,228	2,022,904	52.6%	3,485,597	1,093,099	31.4%

Figure 3-36 shows the positive, negative, and net daily profits for UTCs in 2024.

Figure 3-36 Positive, negative, and net daily UTC profits: 2024

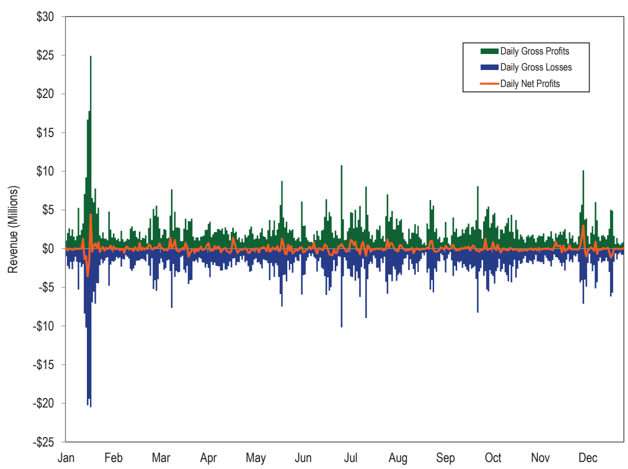

Figure 3-37 shows the cumulative UTC daily total net profits for each year from 2013 through December 2024.[86] Administrative charges are included for all dates, and uplift charges are included starting from November 1, 2020, when uplift was first charged to UTCs.

Figure 3-37 Cumulative daily UTC profits: January 2013 through December 2024

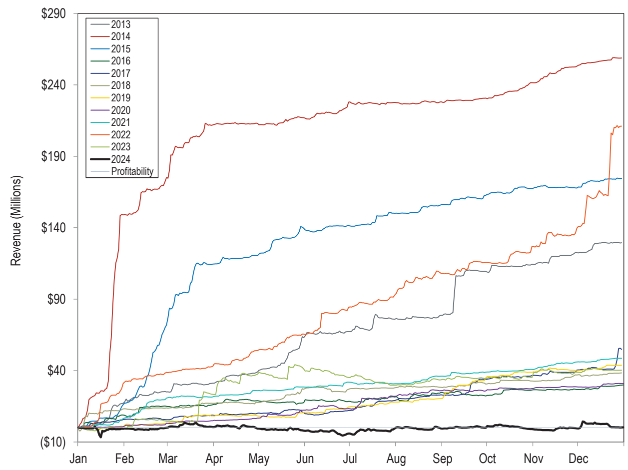

Table 3-49 shows UTC monthly total net profits for January 2013 through December 2024. Administrative charges are included for all months and uplift charges are included starting from November 1, 2020, when uplift was first charged to UTCs. UTC profits were $211 million in 2022, higher than any year 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 2024, but the cleared volume decreased by 27.3 million MWh compared to 2023.

85 Calculations exclude PJM administrative charges.
86 UTCs paid uplift only after October 31, 2020.

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Table 3-49 UTC profits by month: January 2013 through December 2024

	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

Figure 3-38 shows the positive, negative, and net daily profits for INCs and DECs in 2024. 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: 2024[87]

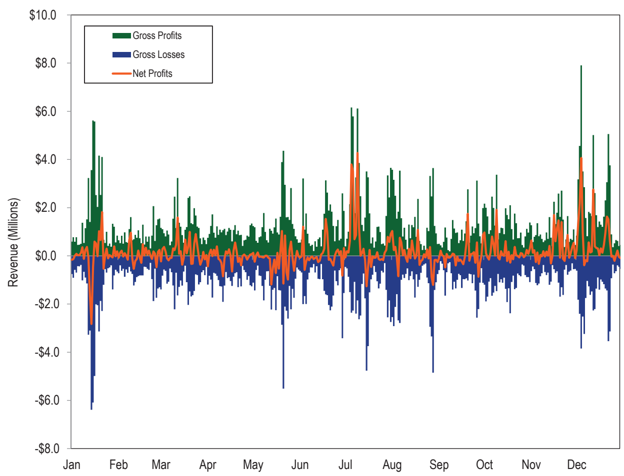


Figure 3-39 shows the positive, negative, and net daily profits for INCs in 2024.

Figure 3-39 Daily gross profits, gross losses, and net profits for INC transactions: 2024[88]

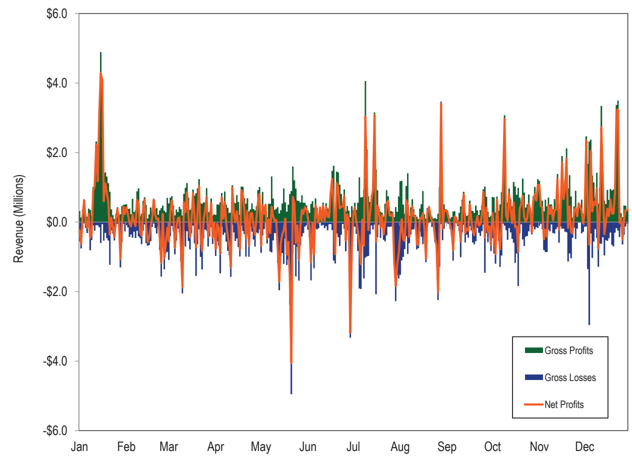
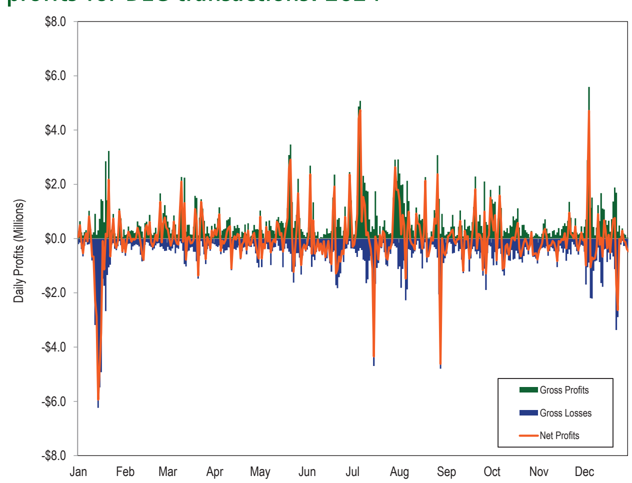


Figure 3-40 shows the positive, negative, and net daily profits for DECs in 2024.

Figure 3-40 Daily gross profits, gross losses, and net profits for DEC transactions: 2024



87 Calculations exclude PJM administrative charges.

88 Calculations exclude PJM administrative charges.

Figure 3-41 shows the cumulative INC and DEC daily profits in 2024. 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: 2024

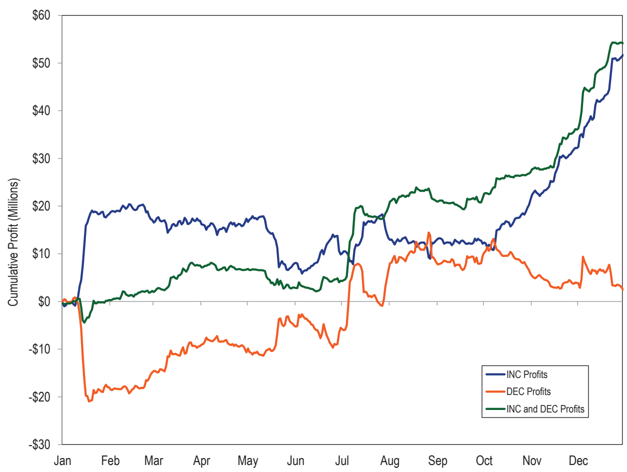


Table 3-50 shows INC and DEC profits by month in 2024.

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.

Table 3-50 INC and DEC profits by month: 2024

Month	January	February	March	April	May	June	July	August	September	October	November	December	Total
INCs	$18,076,775	($971,675)	($189,054)	$441,271	($9,365,934)	$1,864,894	$3,393,030	($411,746)	($735,095)	$9,211,431	$10,850,228	$20,212,254	$52,376,378
DECs	($17,947,177)	$3,060,794	$5,532,446	($1,301,610)	$5,567,967	($415,049)	$12,150,649	$1,536,024	$1,362,084	($3,752,540)	($1,914,206)	($1,444,852)	$2,434,530
INCs and DECs	$129,597	$2,089,120	$5,343,392	($860,339)	($3,797,967)	$1,449,844	$15,543,679	$1,124,277	$626,989	$5,458,891	$8,936,022	$18,767,402	$54,810,908

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 2024, INCs paid a total of $11.3 million, DECs paid a total of $15.4 million, and UTCs paid a total of $38.0 million in uplift. This compares to total INC profits of $52.4 million, total DEC profits of $2.4 million, and total UTC profit of $0.3 million.

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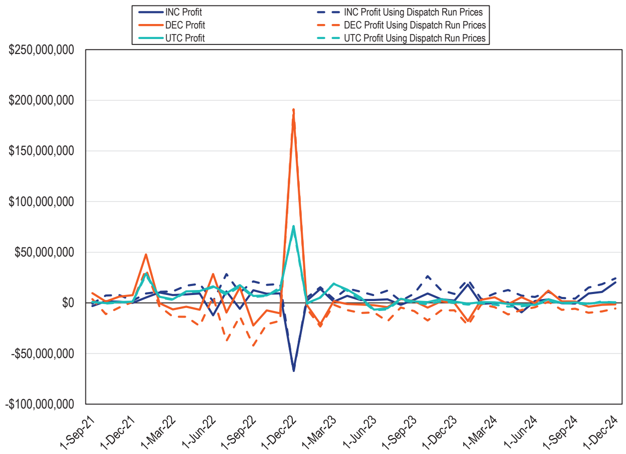
Figure 3-42 Monthly profits for virtuals using pricing run versus dispatch run prices: September 1, 2021 through December 31, 2024



From the implementation of fast start pricing on September 1, 2021, through December 31, 2024, the cumulative difference in profit between the pricing run and the dispatch run for INCs was -$280.2 million, the cumulative difference in profit for DECs was $381.6 million, and the cumulative difference in profit for UTCs was $36.7 million. Fast start pricing led to a net increase of $138.0 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 3-51 shows the difference between the day-ahead and the real-time average LMP in 2023 and 2024.

Table 3-51 Day-ahead and real-time average LMP (Dollars per MWh): 2023 and 2024[89]

	2023				2024			
	Day-Ahead	Real-Time	Difference	Percent of Real-Time	Day-Ahead	Real-Time	Difference	Percent of Real-Time
Average	$30.38	$29.69	($0.69)	(2.3%)	$31.41	$31.32	($0.09)	(0.3%)
Median	$27.98	$25.80	($2.19)	(8.5%)	$26.76	$25.37	($1.39)	(5.5%)
Standard deviation	$14.60	$18.42	$3.82	20.7%	$19.40	$24.84	$5.44	21.9%
Peak average	$36.01	$35.13	($0.88)	(2.5%)	$37.77	$37.32	($0.45)	(1.2%)
Peak median	$32.49	$30.22	($2.28)	(7.5%)	$32.26	$30.17	($2.09)	(6.9%)
Peak standard deviation	$17.12	$21.87	$4.75	21.7%	$22.38	$27.86	$5.48	19.7%
Off peak average	$25.51	$24.97	($0.53)	(2.1%)	$25.86	$26.08	$0.22	0.8%
Off peak median	$23.68	$21.85	($1.83)	(8.4%)	$22.37	$21.30	($1.07)	(5.0%)
Off peak standard deviation	$9.64	$13.08	$3.44	26.3%	$14.20	$20.49	$6.29	30.7%

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

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Table 3-52 shows the difference between the day-ahead and the real-time load-weighted LMP in the first nine months of 2001 through 2024.

Table 3-52 Day-ahead and real-time load-weighted average LMP (Dollars per MWh): 2001 through 2024

	Load-Weighted Average LMP			
	Day-Ahead	Real-Time	Difference	Percent of Real-Time
2001	$36.01	$36.65	$0.64	1.8%
2002	$31.80	$31.60	($0.20)	(0.6%)
2003	$41.43	$41.23	($0.20)	(0.5%)
2004	$42.87	$44.34	$1.47	3.3%
2005	$62.50	$63.46	$0.96	1.5%
2006	$51.33	$53.35	$2.02	3.8%
2007	$57.88	$61.66	$3.78	6.1%
2008	$70.25	$71.13	$0.88	1.2%
2009	$38.82	$39.05	$0.23	0.6%
2010	$47.65	$48.35	$0.70	1.4%
2011	$45.19	$45.94	$0.75	1.6%
2012	$34.55	$35.23	$0.68	1.9%
2013	$38.93	$38.66	($0.26)	(0.7%)
2014	$53.62	$53.14	($0.49)	(0.9%)
2015	$36.73	$36.16	($0.57)	(1.6%)
2016	$29.68	$29.23	($0.45)	(1.5%)
2017	$30.85	$30.99	$0.14	0.5%
2018	$37.97	$38.24	$0.27	0.7%
2019	$27.23	$27.32	$0.08	0.3%
2020	$21.40	$21.77	$0.36	1.7%
2021	$39.37	$39.78	$0.42	1.0%
2022	$75.44	$80.14	$4.71	5.9%
2023	$31.93	$31.08	($0.84)	(2.7%)
2024	$33.79	$33.74	($0.05)	(0.2%)

Table 3-53 includes frequency distributions of the differences between the day-ahead and the real-time load-weighted LMP in 2023 and 2024.

Table 3-53 Frequency distribution by hours of real-time load-weighted LMP minus day-ahead load-weighted LMP (Dollars per MWh): 2023 and 2024

	2023		2024	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($200)	3	0.0%	0	0.0%
($200) to ($100)	10	0.1%	5	0.1%
($100) to ($50)	20	0.4%	49	0.6%
($50) to $0	5,774	66.3%	5,557	63.9%
$0 to $50	2,876	99.1%	3,030	98.4%
$50 to $100	63	99.8%	105	99.6%
$100 to $200	11	100.0%	30	99.9%
$200 to $400	2	100.0%	7	100.0%
$400 to $800	1	100.0%	1	100.0%
>= $800	0	100.0%	0	100.0%

Figure 3-43 shows the differences between day-ahead and real-time hourly average LMP in 2024.

The largest difference was $410.31 per MWh on March 10, 2024.

Figure 3-43 Real-time hourly average LMP minus day-ahead hourly average LMP: 2024

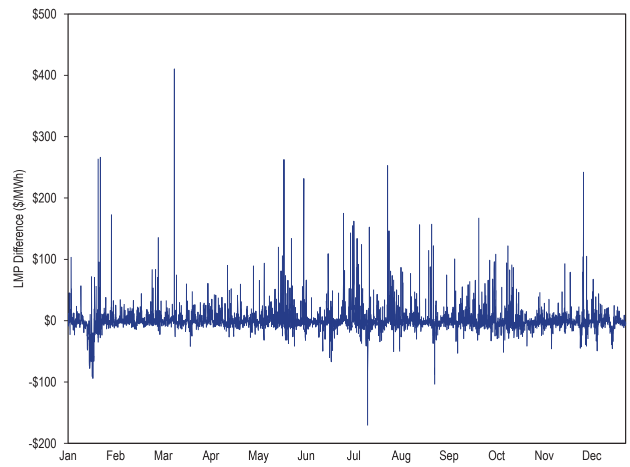
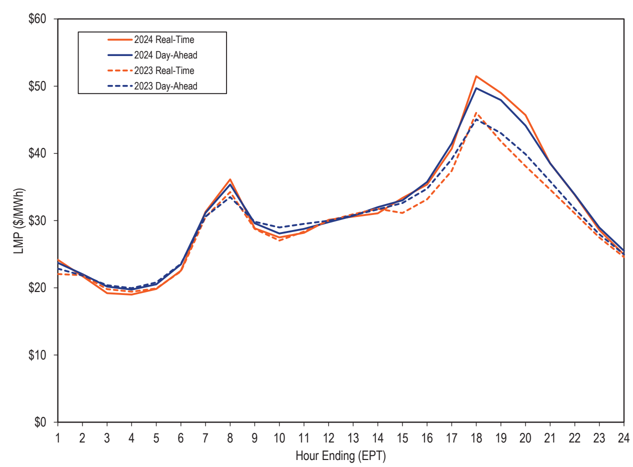


Figure 3-44 shows day-ahead and real-time load-weighted average LMP by hour of the day in 2023 and 2024.

Figure 3-44 System hourly average LMP: 2023 and 2024



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Zonal LMP and Dispatch

Table 3-54 shows real-time zonal average and load-weighted average LMP for 2023 and 2024.

Table 3-54 Real-time zonal average and load-weighted average LMP (Dollars per MWh): 2023 and 2024

	Real-Time Average LMP			Real-Time Load-Weighted Average LMP		
Zone	2023	2024	Percent Change	2023	2024	Percent Change
ACEC	$23.30	$27.52	18.1%	$24.94	$30.60	22.7%
AEP	$30.05	$31.35	4.3%	$31.19	$33.22	6.5%
APS	$31.07	$32.18	3.6%	$32.49	$34.49	6.2%
ATSI	$29.88	$31.32	4.8%	$31.05	$33.32	7.3%
BGE	$36.40	$39.53	8.6%	$38.80	$44.87	15.7%
COMED	$25.82	$25.22	(2.4%)	$27.47	$27.69	0.8%
DAY	$31.28	$32.75	4.7%	$32.70	$35.23	7.7%
DUKE	$30.69	$31.21	1.7%	$32.10	$33.49	4.3%
DOM	$35.75	$36.15	1.1%	$37.50	$39.07	4.2%
DPL	$27.03	$30.94	14.5%	$31.06	$35.67	14.9%
DUQ	$30.14	$31.23	3.6%	$31.31	$33.42	6.8%
EKPC	$30.41	$30.84	1.4%	$31.93	$33.49	4.9%
JCPLC	$24.15	$27.67	14.6%	$25.89	$30.79	18.9%
MEC	$26.59	$28.15	5.9%	$27.93	$30.46	9.1%
OVEC	$29.67	$29.94	0.9%	$29.80	$30.14	1.1%
PECO	$22.34	$27.12	21.4%	$23.63	$29.87	26.4%
PE	$29.81	$31.61	6.0%	$31.01	$33.24	7.2%
PEPCO	$34.36	$37.61	9.4%	$36.59	$42.06	15.0%
PPL	$24.60	$26.58	8.0%	$25.73	$28.53	10.9%
PSEG	$24.32	$28.02	15.2%	$25.66	$30.35	18.3%
REC	$26.04	$29.93	14.9%	$27.90	$32.65	17.0%
PJM	$29.69	$31.32	5.5%	$31.08	$33.74	8.5%

Table 3-55 shows day-ahead zonal average and load-weighted average LMP for 2023 and 2024.

Table 3-55 Day-ahead zonal average and load-weighted average LMP (Dollars per MWh): 2023 and 2024

	Day-Ahead Average LMP			Day-Ahead Load-Weighted Average LMP		
Zone	2023	2024	Percent Change	2023	2024	Percent Change
ACEC	$23.98	$27.54	14.8%	$25.61	$30.37	18.6%
AEP	$31.04	$31.18	0.4%	$32.29	$33.09	2.5%
APS	$32.24	$32.33	0.3%	$33.70	$34.52	2.4%
ATSI	$30.79	$31.47	2.2%	$32.02	$33.36	4.2%
BGE	$38.17	$40.11	5.1%	$40.95	$45.08	10.1%
COMED	$26.68	$25.55	(4.2%)	$28.36	$27.62	(2.6%)
DAY	$32.36	$32.69	1.0%	$33.95	$35.12	3.4%
DUKE	$31.76	$31.28	(1.5%)	$33.40	$33.55	0.4%
DOM	$35.78	$37.02	3.5%	$37.82	$40.12	6.1%
DPL	$26.91	$31.36	16.5%	$31.03	$36.58	17.9%
DUQ	$31.05	$30.97	(0.2%)	$32.43	$33.20	2.4%
EKPC	$31.01	$30.64	(1.2%)	$32.81	$33.41	1.9%
JCPLC	$24.77	$27.57	11.3%	$26.41	$30.14	14.1%
MEC	$27.43	$28.71	4.7%	$29.07	$31.00	6.6%
OVEC	$30.50	$29.93	(1.9%)	$30.40	$29.69	(2.3%)
PECO	$22.92	$27.17	18.5%	$24.28	$29.71	22.4%
PE	$30.52	$32.10	5.2%	$32.28	$34.01	5.4%
PEPCO	$36.13	$38.18	5.7%	$38.83	$43.03	10.8%
PPL	$25.28	$26.82	6.1%	$26.51	$28.70	8.3%
PSEG	$24.95	$27.83	11.6%	$26.35	$29.99	13.8%
REC	$26.72	$30.18	13.0%	$28.92	$32.67	13.0%
PJM	$30.38	$31.41	3.4%	$31.93	$33.79	5.8%

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Figure 3-45 is a map of the real-time load-weighted average LMP in 2024. In the legend, green represents the system marginal price (SMP) and each increment to the right represents five percent of the pricing nodes above SMP and each increment to the left represents 25 percent of the pricing nodes below the SMP.

Figure 3-45 Real-time load-weighted average LMP: 2024

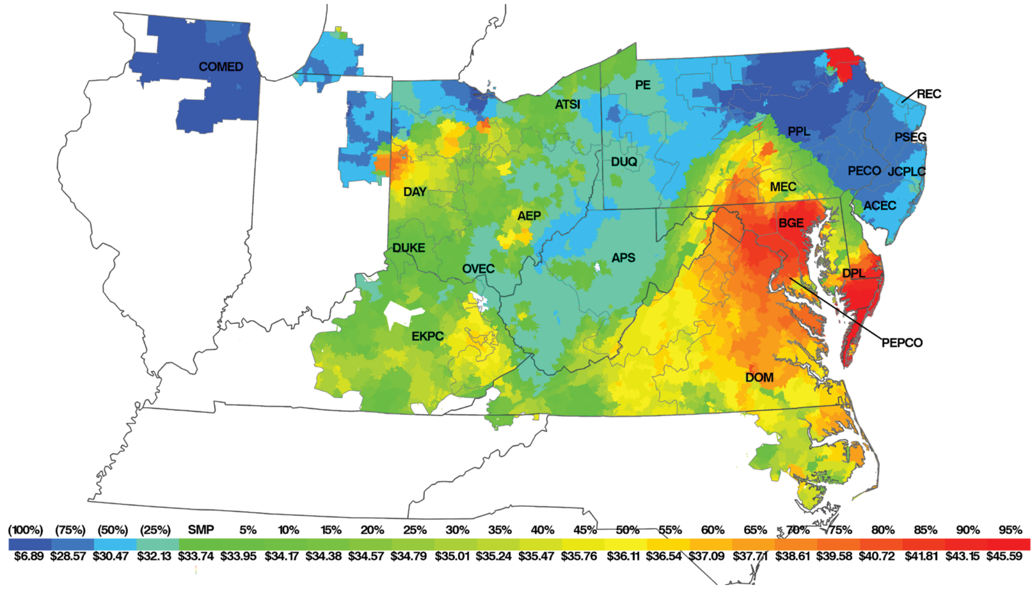
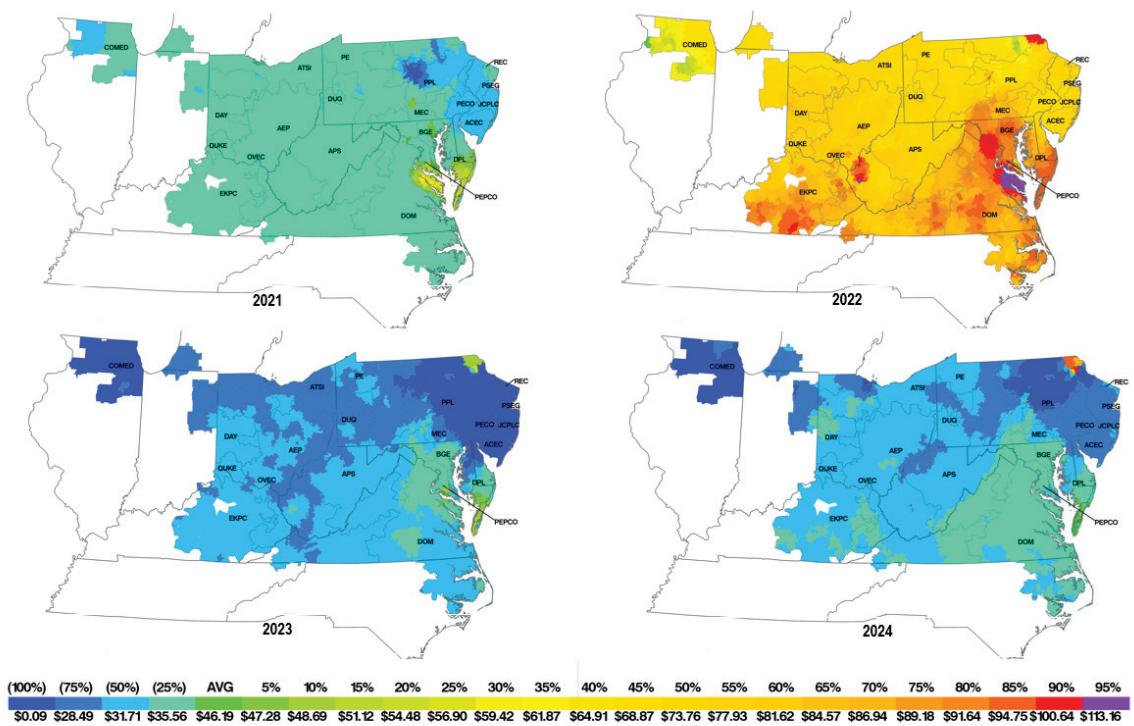


Figure 3-46 includes maps of the real-time load-weighted average LMP in 2021 through 2024. In the legend, green represents the four year average price and each block to the right represents five percent of the pricing nodes above the average price and each block to the left represents 25 percent of the pricing nodes below the average price.

Figure 3-46 Real-time load-weighted average LMP map: 2021 through 2024



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Transmission Constraint Penalty Factors (TCPF)

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

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.[90] 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 3-56 shows the frequency and average shadow price of transmission constraints in the PJM real-time market. In 2024, there were 200,988 transmission constraint five minute intervals in the real-time market with a nonzero shadow price. For about six percent of these transmission constraint intervals, the control limit was violated, meaning that the flow exceeded the facility limit used in SCED.[91] For about 94 percent of those violations, PJM had reduced the control limit on the line rating. In those cases, the actual line limit was not violated. In 2024, the average shadow price of transmission constraints ($1,891.3) when the line limit used in SCED was violated was 8.3 times higher than when the transmission constraint was binding ($227.7) at its limit used in SCED.

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

Table 3-56 Frequency and average shadow price of transmission constraints in the real-time market: 2023 and 2024

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2023	2024	2023	2024
Violated Transmission Constraints	10,252	12,560	$1,493.68	$1,891.28
Binding Transmission Constraints	105,392	131,160	$186.37	$227.74
Market to Market Transmission Constraints	52,204	57,268	$266.37	$266.13
All Transmission Constraints	167,848	200,988	$291.10	$342.64

Table 3-57 shows the frequency and average shadow price of transmission constraints in the PJM day-ahead market. In 2024, there were 78,305 transmission constraint hours in the day-ahead market with a nonzero shadow price. For less than one percent of these transmission constraint hours, the line limit was violated, meaning that the flow exceeded the facility limit used in the day-ahead pricing run solution.

Table 3-57 Frequency and average shadow price of transmission constraints in the day-ahead market: 2023 and 2024

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2023	2024	2023	2024
Violated Transmission Constraints	15	34	$2,000.00	$2,000.00
Binding Transmission Constraints	66,024	69,856	$44.27	$66.91
Market to Market Transmission Constraints	7,495	8,415	$113.62	$102.44
All Transmission Constraints	73,534	78,305	$51.74	$71.57

90 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.

91 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.

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Table 3-58 shows the frequency of violated transmission constraints by voltage level in the real-time market. In 2024, 83.9 percent of the violated transmission constraint intervals had a voltage level at or below 230 kV.

Table 3-58 Frequency of PJM violated transmission constraints in the real-time market by voltage: 2023 and 2024

	2023		2024	
Voltage	Frequency (Constraint Intervals)	Percent	Frequency (Constraint Intervals)	Percent
1 kV	113	1.1%	79	0.6%
69 kV	395	3.9%	931	7.4%
115 kV	1,968	19.2%	3,004	23.9%
138 kV	3,125	30.5%	3,769	30.0%
161 kV	-	0.0%	16	0.1%
230 kV	3,660	35.7%	2,743	21.8%
345 kV	676	6.6%	788	6.3%
500 kV	306	3.0%	1,005	8.0%
765 kV	9	0.1%	225	1.8%
Total	10,252	100.0%	12,560	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. 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.[92] This could be the result of a lengthy planned transmission outage, for example.[93] 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.

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 changes to the transmission constraint penalty factors for constraints that are violated due to a transmission outage for which limited generation resources are available to provide relief.[94]

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, triggering the use of transmission constraint penalty factors.[95] 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 3-59 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 2024, there were 11,744 or 94 percent of 12,560 violated transmission constraint intervals in the real-time market with a control limit less than 100 percent. In 2024, among the constraints with a reduced control limit, the constraint limit was reduced on average by 5.1 percent.

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

94 See 182 FERC ¶ 61,183 (March 21, 2023).
95 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.

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Table 3-59 Frequency of reduction in control limit of line ratings (constraint intervals) in the real-time market: 2023 and 2024

	Frequency (Constraint Intervals)		Constraints with Reduced Control Percent (Constraint Intervals)		Average Reduction (Percent)	
Description	2023	2024	2023	2024	2023	2024
Violated Transmission Constraints	10,252	12,560	7,213	11,744	5.5%	5.1%
Binding Transmission Constraints	105,392	131,160	103,491	130,108	6.3%	5.3%
Market to Market Transmission Constraints	52,204	57,268	14,355	20,069	5.7%	6.0%
All Transmission Constraints	167,848	200,988	125,059	161,921	6.2%	5.4%

Table 3-60 shows the reasons provided by the PJM operators for changing the control limit on the line rating for violated transmission constraints. In 2024, of the 11,744 violated transmission constraint intervals with reduced control limits, 978 or 9.1 percent were reduced because the relief calculated by the SCED optimization was less than the operator's desired relief for the transmission constraint. No reason was provided for 10,007 instances, or 85 percent of all the instances. 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 3-60 PJM's reasons for reduction in control limits of line ratings (constraint intervals) in the real-time market: 2023 and 2024

	Constraint Intervals		Average Reduction (Percent)	
Reason	2023	2024	2023	2024
No reason provided	5,221	10,007	4.5%	4.6%
Prepositioning of generation resources to support an operational requirement	104	77	11.3%	8.5%
Inadequate relief calculated by the SCED optimization	978	1,071	7.2%	6.8%
Transmission owner identified the flow on their constraint to be greater than PJM's calculated flow on the same constraint.	203	101	8.1%	8.5%
Modeled constraint is a thermal surrogate	30	107	67.1%	22.5%
Power flow on the constraint is volatile due to various system conditions	677	381	6.8%	7.4%
All violated constraints	7,213	11,744	5.5%	5.1%

Table 3-61 shows the impact on LMP of PJM dispatchers reducing the control limit of line ratings of transmission constraints and causing artificial line limit violations.[96] The transmission penalty factor contribution to the load-weighted average LMP in 2024 was $3.00 per MWh. If 100 percent of the line limits had been used for the PJM transmission constraints and everything else remained unchanged, fewer constraints would have been violated and the transmission penalty factor's contribution to the load-weighted average LMP would have decreased to $0.02 per MWh or 99.4 percent lower.

Table 3-61 Real-time LMP effect of reduced control limits on transmission constraint line ratings (Dollars per MWh): 2023 and 2024

	Contribution to LMP	
Line Limit Scenario for Violated Constraints	2023	2024
Line Limits Reduced by PJM (Actual)	$1.62	$3.00
Hypothetical Use of Full Line Limits	$0.01	$0.02
Change in Contribution to LMP	($1.61)	($2.98)
Percent Change in Contribution to LMP	(99.3%)	(99.4%)

Table 3-62 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 2024, there were 11,769 or 94 percent of violated transmission constraint intervals in the real-time market with a transmission penalty factor equal to the default $2,000 per MWh.

96 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 3-62 Frequency of changes to the magnitude of transmission penalty factor (constraint intervals) in the real-time market: 2023 and 2024

	2023			2024		
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	7,503	-	2,749	11,769	-	791
Binding Transmission Constraints	103,853	-	1,539	130,783	-	377
Market to Market Transmission Constraints	2,657	-	49,547	7,526	17	49,725
All Transmission Constraints	114,013	-	53,835	150,078	17	50,893

Prior to September 1, 2022, transmission constraint penalty factors frequently set prices when PJM modeled a surrogate constraint to limit the dispatch of a generator that would experience voltage instability at its full output due to a transmission outage. Since September 1, 2022, PJM is using a generator output limit constraint to manage generator voltage instability issues. In 2024, there were 25,634 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.

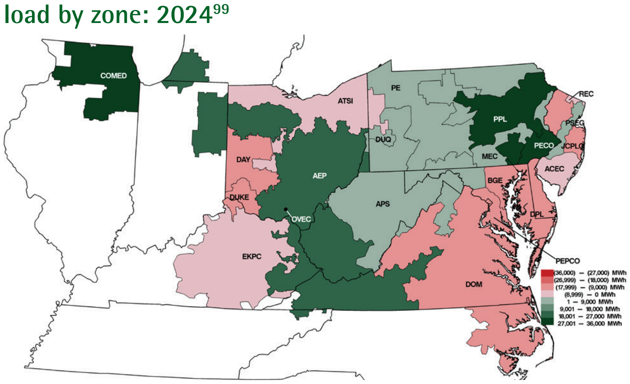
PJM used CT pricing logic until the implementation of fast start pricing on September 1, 2021, to force otherwise uneconomic resources to be marginal and set price in the day-ahead and real-time market solutions. In the event PJM committed a resource that was uneconomic and/or offered with inflexible parameters, PJM used CT pricing logic to model a constraint with a variable flow limit, paired with an artificial override of the inflexible resource's economic minimum, to force the resource to be marginal in the PJM market solution.[97] Frequently, PJM operators also manually overrode the transmission violation penalty factor of the constraint to match the offer price of the resource to artificially control the shadow price of the constraint.

PJM's use of CT pricing logic was inconsistent with the efficient market dispatch and pricing. For that reason, in 2019, FERC declared CT pricing logic to be unjust and unreasonable.[98] PJM continues to use similar methods to artificially change the prices, like using thermal surrogates and forcing units to be marginal. These practices can lead to inefficient market outcomes.

Net Generation by Zone

Figure 3-47 shows the difference between the PJM real-time generation and real-time load by zone in2024. 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 3-63 shows the difference between the real-time generation and real-time load by zone in 2023 and 2024.

Figure 3-47 Map of real-time generation less real-time load by zone: 2024[99]



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

98 167 FERC ¶ 61,058 at P 69 (2019).

99 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>.

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Table 3-63 Real-time generation less real-time load by zone (GWh): 2023 and 2024

Zonal Generation and Load (GWh)						
	2023			2024		
Zone	Generation	Load	Net	Generation	Load	Net
ACEC	2,577	9,482	(6,904)	1,575	9,720	(8,145)
AEP	151,688	122,300	29,388	153,289	127,875	25,414
APS	52,690	46,549	6,141	49,815	47,856	1,959
ATSI	52,450	63,747	(11,297)	54,539	65,702	(11,163)
BGE	16,602	28,951	(12,349)	17,420	29,969	(12,550)
COMED	134,459	89,033	45,426	138,165	90,905	47,260
DAY	1,427	16,491	(15,063)	2,051	17,059	(15,008)
DUKE	9,840	25,172	(15,331)	13,109	26,026	(12,917)
DOM	92,891	113,612	(20,721)	105,303	121,532	(16,229)
DPL	4,955	17,528	(12,572)	5,076	18,168	(13,093)
DUQ	16,229	12,809	3,419	15,502	13,319	2,183
EKPC	8,824	13,129	(4,305)	9,300	13,776	(4,477)
JCPLC	9,056	20,993	(11,937)	8,246	21,650	(13,404)
MEC	17,516	14,708	2,809	18,198	14,964	3,234
OVEC	9,582	117	9,464	9,988	116	9,872
PECO	75,805	36,689	39,116	75,063	38,004	37,059
PE	27,629	16,037	11,592	27,976	16,530	11,446
PEPCO	10,340	26,747	(16,407)	10,580	27,616	(17,036)
PPL	70,288	38,849	31,439	74,792	39,806	34,986
PSEG	45,075	40,744	4,332	42,861	42,180	681
REC	0	1,366	(1,366)	0	1,411	(1,411)

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 3-64 shows PJM generation by fuel source in GWh for 2023 and 2024.

In 2024, generation from coal units increased 1.4 percent, generation from natural gas units increased 3.5 percent, generation from oil units increased 53.1 percent, generation from wind units increased 8.5 percent, and generation from solar units increased 58.1 percent compared to 2023.

Table 3-64 Generation (By fuel source (GWh)): 2023 and 2024[100 101]

	2023		2024		Change in
	GWh	Percent	GWh	Percent	Output
Coal	120,876.1	14.7%	122,583.3	14.5%	1.4%
Bituminous	108,651.3	13.2%	107,270.7	12.7%	(1.3%)
Sub Bituminous	6,428.1	0.8%	9,548.2	1.1%	48.5%
Other Coal	5,796.7	0.7%	5,764.4	0.7%	(0.6%)
Nuclear	273,488.6	33.3%	272,744.4	32.2%	(0.3%)
Gas	363,659.7	44.3%	376,249.8	44.5%	3.5%
Natural Gas CC	331,767.3	40.4%	340,951.1	40.3%	2.8%
Natural Gas CT	21,077.7	2.6%	20,916.2	2.5%	(0.8%)
Natural Gas Other Units	9,570.7	1.2%	13,250.0	1.6%	38.4%
Other Gas	1,244.0	0.2%	1,132.6	0.1%	(9.0%)
Hydroelectric	15,488.8	1.9%	16,001.4	1.9%	3.3%
Pumped Storage	6,096.5	0.7%	6,430.5	0.8%	5.5%
Run of River	7,644.6	0.9%	7,624.6	0.9%	(0.3%)
Other Hydro	1,747.6	0.2%	1,946.3	0.2%	11.4%
Wind	28,937.2	3.5%	31,384.5	3.7%	8.5%
Waste	3,992.6	0.5%	3,912.1	0.5%	(2.0%)
Oil	2,676.7	0.3%	4,098.6	0.5%	53.1%
Heavy Oil	38.2	0.0%	156.8	0.0%	310.4%
Light Oil	918.5	0.1%	2,188.2	0.3%	138.2%
Diesel	40.4	0.0%	32.4	0.0%	(19.8%)
Other Oil	1,679.6	0.2%	1,721.2	0.2%	2.5%
Solar	11,097.7	1.4%	17,547.7	2.1%	58.1%
Battery	28.7	0.0%	51.7	0.0%	80.4%
Biofuel	1,265.0	0.2%	1,249.4	0.1%	(1.2%)
Total	821,511.0	100.0%	845,823.0	100.0%	3.0%

100 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.

101 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.

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Table 3-65 Monthly generation (By fuel source (GWh)): 2024

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Coal	15,756.3	8,438.5	6,794.2	7,545.8	9,134.6	13,401.5	14,413.2	13,168.5	7,342.9	6,934.1	7,166.0	12,487.7	122,583.3
Bituminous	13,683.1	7,179.2	6,137.1	6,860.5	8,463.1	11,375.1	11,900.0	11,317.8	6,691.4	6,459.6	6,275.8	10,928.1	107,270.7
Sub Bituminous	1,504.1	679.7	0.5	72.0	275.1	1,450.0	1,828.9	1,478.8	379.6	169.5	629.3	1,080.5	9,548.2
Other Coal	569.1	579.5	656.5	613.3	396.4	576.4	684.3	371.9	271.9	305.1	261.0	479.0	5,764.4
Nuclear	24,729.8	22,462.5	21,926.5	19,070.3	22,113.0	23,205.6	23,661.2	24,076.1	22,570.4	21,998.0	21,945.5	24,985.6	272,744.4
Gas	32,516.5	30,491.6	29,868.6	26,303.4	27,432.1	34,274.7	40,391.9	38,035.2	32,595.4	25,958.9	27,210.2	31,171.2	376,249.8
Natural Gas CC	30,212.2	29,364.4	28,351.4	23,260.0	24,193.0	30,702.7	34,585.9	33,645.0	29,670.2	22,766.1	24,715.8	29,484.2	340,951.1
Natural Gas CT	1,644.7	718.0	1,026.3	2,077.4	2,132.6	1,833.4	2,896.7	2,362.8	1,844.4	1,912.4	1,387.4	1,080.1	20,916.2
Natural Gas Other Units	554.4	312.7	392.5	875.5	1,013.2	1,647.9	2,812.8	1,929.9	987.0	1,188.0	1,020.2	516.0	13,250.0
Other Gas	105.1	96.4	98.4	90.4	93.3	90.7	96.6	97.5	93.9	92.5	86.9	90.9	1,132.6
Hydroelectric	1,751.3	1,467.0	1,512.3	1,376.4	1,589.3	1,359.4	1,387.5	1,624.1	1,024.9	750.7	828.9	1,329.6	16,001.4
Pumped Storage	536.0	525.0	403.2	366.7	567.3	688.9	774.7	745.9	580.9	331.0	423.3	487.5	6,430.5
Run of River	1,065.8	798.3	1,015.2	915.7	845.3	405.4	319.4	612.2	287.4	346.9	304.0	708.9	7,624.6
Other Hydro	149.5	143.7	93.9	94.0	176.6	265.1	293.4	266.0	156.6	72.7	101.5	133.2	1,946.3
Wind	3,127.6	2,975.8	3,890.8	3,569.3	2,136.5	2,233.5	1,151.4	1,233.7	1,496.2	2,670.5	3,402.6	3,496.7	31,384.5
Waste	329.6	321.3	329.6	308.9	357.2	337.4	329.1	335.8	287.2	314.0	315.0	346.9	3,912.1
Oil	290.3	134.0	178.1	222.2	460.5	411.5	784.9	489.0	316.9	306.6	230.3	274.3	4,098.6
Heavy Oil	12.0	0.0	0.0	31.3	13.8	2.3	42.6	17.8	0.0	0.0	0.4	36.6	156.8
Light Oil	101.0	17.5	27.3	40.8	286.4	274.8	575.4	305.5	211.5	183.8	78.3	85.8	2,188.2
Diesel	13.5	0.1	0.3	0.4	0.8	1.8	4.9	2.3	0.5	2.0	1.1	4.7	32.4
Other Oil	163.7	116.3	150.5	149.8	159.5	132.6	162.1	163.4	104.9	120.9	150.5	147.1	1,721.2
Solar	583.0	1,047.7	1,269.1	1,487.2	1,680.7	2,189.0	2,100.4	2,016.8	1,539.6	1,732.7	995.9	905.7	17,547.7
Battery	4.6	4.6	5.7	4.4	5.0	3.3	3.1	3.5	3.6	4.4	4.4	4.9	51.7
Biofuel	135.3	118.7	87.7	104.6	92.2	136.6	116.3	129.8	76.8	42.1	76.3	133.1	1,249.4
Total	79,224.4	67,461.7	65,862.6	59,992.5	65,000.9	77,552.3	84,339.0	81,112.5	67,254.0	60,712.1	62,175.0	75,135.7	845,823.0

Table 3-66 shows the difference between the day-ahead and the real-time average generation by fuel source.

Table 3-66 Day-ahead and real-time average generation (By fuel source (GWh)): 2024

	2024					
	Day-Ahead		Real-Time			Percent
	GWh	Percent	GWh	Percent	RT - DA	Difference
Coal	123,678.9	15.1%	122,583.3	14.5%	(1,095.6)	(0.9%)
Bituminous	107,861.6	13.1%	107,270.7	12.7%	(590.8)	(0.5%)
Sub Bituminous	10,241.6	1.2%	9,548.2	1.1%	(693.4)	(6.8%)
Other Coal	5,575.8	0.7%	5,764.4	0.7%	188.7	3.4%
Nuclear	268,212.4	32.7%	272,744.4	32.2%	4,532.0	1.7%
Gas	369,346.4	45.0%	376,249.8	44.5%	6,903.4	1.9%
Natural Gas CC	336,373.8	41.0%	340,951.1	40.3%	4,577.2	1.4%
Natural Gas CT	18,484.2	2.3%	20,916.2	2.5%	2,432.0	13.2%
Natural Gas Other Units	13,420.9	1.6%	13,250.0	1.6%	(170.9)	(1.3%)
Other Gas	1,067.5	0.1%	1,132.6	0.1%	65.1	6.1%
Hydroelectric	15,347.7	1.9%	16,001.4	1.9%	653.7	4.3%
Pumped Storage	7,503.9	0.9%	6,430.5	0.8%	(1,073.4)	(14.3%)
Run of River	7,843.8	1.0%	7,624.6	0.9%	(219.2)	(2.8%)
Other Hydro	0.0	0.0%	1,946.3	0.2%	1,946.3	NA
Wind	21,563.7	2.6%	31,384.5	3.7%	9,820.9	45.5%
Waste	3,889.7	0.5%	3,912.1	0.5%	22.4	0.6%
Oil	3,904.7	0.5%	4,098.6	0.5%	193.9	5.0%
Heavy Oil	119.0	0.0%	156.8	0.0%	37.7	31.7%
Light Oil	2,170.4	0.3%	2,188.2	0.3%	17.8	0.8%
Diesel	13.0	0.0%	32.4	0.0%	19.4	149.7%
Other Oil	1,602.3	0.2%	1,721.2	0.2%	119.0	7.4%
Solar	13,419.2	1.6%	17,547.7	2.1%	4,128.5	30.8%
Battery	23.2	0.0%	51.7	0.0%	28.5	123.0%
Biofuel	1,219.2	0.1%	1,249.4	0.1%	30.2	2.5%
Total	820,605.1	100.0%	845,823.0	100.0%	25,217.8	3.1%

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Table 3-67 shows the share of generation by natural gas, coal, nuclear and other fuel types in the real-time energy market since 2008. Generation from natural gas was 44.3 percent, the highest level for the same period since the start of PJM markets, and coal was 14.5 percent, the lowest level for the same period since the start of PJM markets.

Table 3-67 Share of generation by fuel source: 2008 through 2024

	Natural Gas	Coal	Nuclear	Other Fuel Type
2008	7.4%	54.9%	34.7%	3.0%
2009	10.0%	50.3%	35.9%	3.7%
2010	11.7%	49.3%	34.6%	4.4%
2011	14.1%	47.1%	34.5%	4.3%
2012	18.8%	42.1%	34.6%	4.5%
2013	16.7%	44.2%	34.8%	4.3%
2014	17.8%	43.3%	34.4%	4.5%
2015	23.0%	36.2%	35.5%	5.3%
2016	26.5%	33.9%	34.4%	5.3%
2017	26.8%	31.8%	35.6%	5.9%
2018	30.6%	28.6%	34.2%	6.6%
2019	36.2%	23.8%	33.6%	6.4%
2020	39.6%	19.3%	34.2%	6.9%
2021	37.7%	22.2%	32.8%	7.4%
2022	39.8%	20.0%	32.3%	7.9%
2023	44.1%	14.7%	33.3%	7.9%
2024	44.3%	14.5%	32.2%	8.9%

Fuel Diversity

Figure 3-48 shows the fuel diversity index (FDI_e) for PJM energy generation.[102] 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 3-64 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 28.6 percent from 2012 through December 2024. 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.[103] 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 54.9 percent for 2008 and 14.5 percent for 2024. Gas generation as a share of total generation was 7.4 percent for 2008 and 44.4 percent for 2024. Wind and solar generation as a share of total generation was 0.5 percent for 2008 and 5.8 percent for 2024.

The FDI_e increased 0.8 percent in 2024 compared to 2023.

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.[104] This capacity consists primarily of coal steam plants and CTs. The units expected to retire by the end of 2025 generated 37,033.8 GWh in 2024. The dashed line (green) in Figure 3-48 shows a counterfactual result for FDI_e assuming the 37,033.8 GWh of generation from uneconomic units and expected 2025 retirements were replaced by gas, wind and solar generation.[105] The FDI_e for 2024 under this counterfactual assumption would have been 1.4 percent lower than the actual FDI_e. The units expected to retire by the end of 2030 generated 68,146.1 GWh in 2024. Replacing this generation with gas, wind and solar generation results in a counterfactual FDI_e that is 1.4 percent higher than the actual FDI_e.[106] The dashed line (blue) in Figure 3-48 shows a counterfactual result for FDI_e assuming that this generation is replaced with gas, wind and solar generation.

102 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.

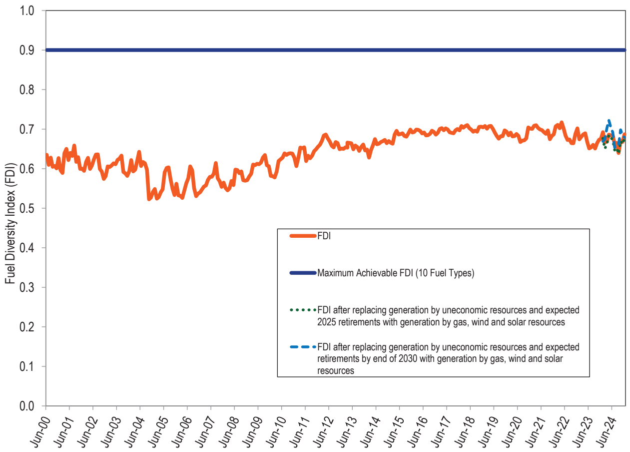
103 See the *2019 Annual State of the Market Report for PJM*, Volume 2, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton Zones occurred in October 2004.

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

105 It is assumed that 11,907.4 GWh of the replacement energy will be from new wind and solar units. This value represents the increase over 2024 levels in renewable generation that is required by RPS in 2025. The split between solar (59.7 percent) and wind (40.3 percent) is based on queue data and 2024 capacity factors in Table 8-33 and Table 8-37.

106 It is assumed that 55,110.7 GWh of the replacement energy will be from new wind and solar units. This value represents the increase over 2024 levels in renewable generation that is required by RPS in 2030. The split between solar (59.7 percent) and wind (40.3 percent) is based on queue data and 2024 capacity factors in Table 8-33 and Table 8-37.

Figure 3-48 Fuel diversity index for monthly generation: June 2000 through December 2024



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 3-68 shows the approved nomination deadlines and corresponding start time of gas flow.[107] Pipelines provide that firm service requests may replace, or bump, interruptible nominations on the pipeline under defined conditions.

Table 3-68 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 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

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

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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 3-68. 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 3-69 shows the notification time gas fired generators should be requesting and submitting when pipelines require nominating per the NAESB cycle deadlines.

Table 3-69 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

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and request temporary parameter exceptions.[108] The resultant guidelines were posted by the MMU and PJM on September 8, 2023.[109]

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 3-70 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 2024, coal units were 10.3 percent and natural gas units were 73.7 percent of marginal resources. In 2024, natural gas combined cycle units were 60.8 percent of marginal resources. In 2023, coal units were 9.1 percent and natural gas units were 83.1 percent of the total marginal resources. In 2023, natural gas combined cycle units were 69.2 percent of the total marginal resources. In 2024, 58.5 percent of the wind marginal units had negative offer prices, 34.9 percent had zero offer prices and 6.6 percent of the wind marginal units had positive offer prices. In 2023, 54.7 percent of the wind marginal units had negative offer prices, 44.2 percent had zero offer prices and 1.0 percent had positive offer prices.

The proportion of marginal nuclear units decreased from 0.62 percent in 2023 to 0.40 percent in 2024. 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 3-70 are from the pricing run, which may not be the same as marginal resources from the dispatch run.

108 "Gas Nomination Cycles and Units Operating Parameters," Electric Gas Coordination Senior Task Force (EGCSTF), August 15, 2023.

109 *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 3-70 Type of fuel used and technology (By real-time marginal units): 2020 through 2024[110]

Fuel	Technology	2020	2021	2022	2023	2024
Gas	CC	64.33%	59.75%	61.66%	69.20%	60.79%
Wind	Wind	6.75%	11.04%	11.12%	5.53%	13.55%
Coal	Steam	17.53%	14.15%	10.02%	9.14%	10.27%
Gas	CT	5.89%	10.06%	11.26%	11.01%	9.68%
Gas	Steam	2.12%	1.17%	1.42%	1.83%	2.61%
Oil	CT	1.25%	1.13%	2.25%	0.91%	1.21%
Gas	RICE	0.29%	0.67%	0.86%	1.09%	0.58%
Uranium	Steam	1.35%	1.00%	0.39%	0.62%	0.40%
Other	Solar	0.33%	0.76%	0.74%	0.02%	0.38%
Oil	RICE	0.04%	0.06%	0.11%	0.18%	0.15%
Oil	Steam	0.06%	0.06%	0.03%	0.06%	0.15%
Municipal Waste	RICE	0.00%	0.00%	0.00%	0.06%	0.08%
Municipal Waste	Steam	0.02%	0.02%	0.04%	0.12%	0.06%
Other	Steam	0.03%	0.08%	0.05%	0.04%	0.05%
Oil	CC	0.00%	0.02%	0.06%	0.19%	0.02%
Other	Battery	0.00%	0.00%	0.00%	0.00%	0.00%
Landfill Gas	CT	0.01%	0.01%	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 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): 2004 through 2024

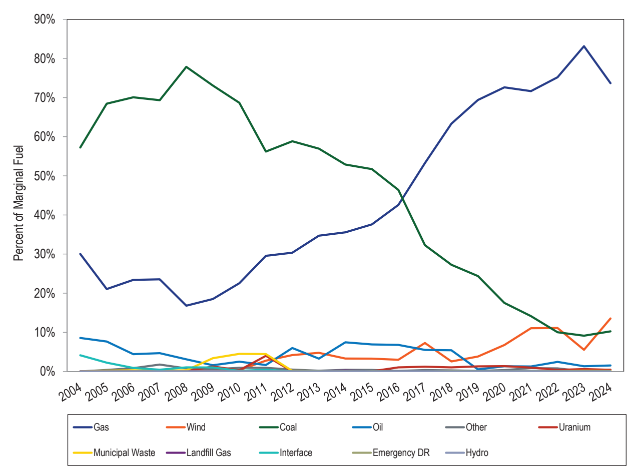

Table 3-71 shows the type of fuel and technology by fast start marginal resources and other marginal resources in the real-time energy market in 2024. In 2024, marginal fast start resources accounted for 5.79 percent of all marginal resources in the pricing run.

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

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Table 3-71 Fuel type and technology (Real-time marginal units and fast start marginal units): 2024

		2024		
Fuel	Technology	Fast Start	Other	Both
Coal	Steam	0.00%	10.27%	10.27%
Gas	CC	0.00%	60.79%	60.79%
Gas	CT	4.33%	5.35%	9.68%
Gas	RICE	0.58%	0.01%	0.58%
Gas	Steam	0.00%	2.61%	2.61%
Landfill Gas	CT	0.00%	0.00%	0.00%
Municipal Waste	RICE	0.02%	0.06%	0.08%
Municipal Waste	Steam	0.00%	0.06%	0.06%
Oil	CC	0.00%	0.02%	0.02%
Oil	CT	0.56%	0.65%	1.21%
Oil	RICE	0.13%	0.02%	0.15%
Oil	Steam	0.00%	0.15%	0.15%
Other	Battery	0.00%	0.00%	0.00%
Other	Solar	0.02%	0.36%	0.38%
Other	Steam	0.00%	0.05%	0.05%
Uranium	Steam	0.00%	0.40%	0.40%
Wind	Wind	0.16%	13.39%	13.55%
All Marginal Units		5.79%	94.21%	100.00%

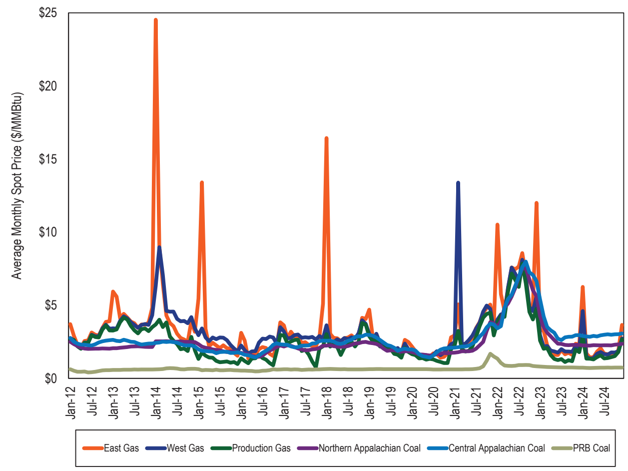
Fuel Price Trends and LMP

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 2024. Natural gas prices were mixed, while coal prices and oil prices decreased in 2024 compared to 2023. In 2024, the price of eastern natural gas was 6.0 percent higher and the price of western natural gas was 3.4 percent lower than in 2023. The price of Northern Appalachian coal was 16.1 percent lower; the price of Central Appalachian coal was 9.9 percent lower; and the price of Powder River Basin coal was 3.9 percent lower.[111] The price of ULSD NY Harbor Barge was 22.2 percent lower in 2024 than in 2023.

111 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.

Figure 3-50 Spot average fuel price comparison: 2012 through 2024 ($/MMBtu)



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.[112] 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

112 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. A challenge to Virginia's leaving RGGI is pending. See Floyd County Circuit Court, Virginia, Case No. CL23000173-00.

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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.[113]

Starting on September 1, 2021, the components shown in Table 3-72 and Table 3-74 are from the pricing run which includes the impact of amortized start cost and amortized no load cost of the fast start marginal units. The components of LMP are shown in Table 3-72, including markup using unadjusted cost-based offers.[114] Table 3-72 shows that in 2024, 12.1 percent of the load-weighted LMP was the result of coal costs, 39.7 percent was the result of gas costs and 5.8 percent was the result of the cost of carbon emission allowances. Using unadjusted cost-based offers, negative markup was -10.6 percent of the load-weighted LMP. Using unadjusted cost-based offers, positive markup was 10.6 percent of the load-weighted LMP. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP and does not reflect the other components of the offers of units burning that fuel. LMP may, at times, be set by transmission constraint penalty factors. In 2024, 8.9 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 removed the constraint relaxation logic and allowed penalty factors to affect LMPs starting in February 2019. The component NA is the unexplained portion of load-weighted LMP. For several intervals, PJM failed to provide all the data needed to accurately calculate generator sensitivity factors. As a result, the LMP for those intervals cannot be decomposed into component costs. The NA component is the cumulative effect of excluding those five minute intervals. The percent column is the difference (in percentage points) in the proportion of LMP represented by each component in 2023 and 2024.

Table 3-72 Components of real-time (Unadjusted) load-weighted average LMP: 2023 and 2024

	2023		2024		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$13.60	43.7%	$13.41	39.7%	(4.0%)
Coal	$4.49	14.4%	$4.09	12.1%	(2.3%)
Positive Markup	$3.29	10.6%	$3.56	10.6%	(0.0%)
Variable Maintenance	$2.31	7.4%	$3.18	9.4%	2.0%
Transmission Constraint Penalty Factor	$1.62	5.2%	$3.01	8.9%	3.7%
Ten Percent Adder	$1.95	6.3%	$2.00	5.9%	(0.3%)
CO_2 Cost	$1.93	6.2%	$1.94	5.8%	(0.5%)
Variable Operations	$1.10	3.5%	$1.43	4.2%	0.7%
Ancillary Service Redispatch Cost	$0.50	1.6%	$1.33	3.9%	2.3%
Opportunity Cost Adder	$0.87	2.8%	$1.24	3.7%	0.9%
Oil	$0.31	1.0%	$1.08	3.2%	2.2%
Market-to-Market	$0.41	1.3%	$0.34	1.0%	(0.3%)
Increase Generation Differential	$0.13	0.4%	$0.24	0.7%	0.3%
LPA Rounding Difference	$0.40	1.3%	$0.18	0.5%	(0.8%)
Scarcity	$0.07	0.2%	$0.17	0.5%	0.3%
NA	$0.15	0.5%	$0.09	0.3%	(0.2%)
NO_x Cost	$0.51	1.6%	$0.09	0.3%	(1.4%)
Landfill Gas	$0.06	0.2%	$0.05	0.2%	(0.0%)
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%
Decrease Generation Differential	($0.01)	(0.0%)	($0.04)	(0.1%)	(0.1%)
Renewable Energy Credits	($0.07)	(0.2%)	($0.07)	(0.2%)	0.0%
Negative Markup	($2.56)	(8.2%)	($3.58)	(10.6%)	(2.4%)
Total	$31.08	100.0%	$33.74	100.0%	0.0%

Components of Change in LMP

Table 3-73 shows the components of the increase in real-time load-weighted average LMP from 2023 to 2024. In 2024, the real-time load-weighted average LMP increased by $2.66 per MWh, 8.5 percent. Fuel and consumables cost components of LMP (the sum of gas, coal, oil, landfill gas, variable operations) increased the LMP by $0.50 per MWh, 18.9 percent of increase

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

114 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>.

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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 $0.05 per MWh, -1.9 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 $0.16 per MWh, 6.2 percent of the increase in LMP. The scarcity component increased the LMP by $0.10 per MWh, 3.7 percent of the increase in the LMP. The transmission constraint penalty factor increased the LMP by $1.39 per MWh, 52.4 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, increased the LMP by $0.83 per MWh, 31.2 percent.

Table 3-73 Components of Change in real-time load-weighted average LMP: 2023 and 2024

Component	2023	2024	Change in LMP	Percent of Total Change
Fuel and Consumables	$19.56	$20.06	$0.50	18.9%
Emission Related	$3.24	$3.19	($0.05)	(1.9%)
Market Power Related	$4.99	$5.16	$0.16	6.2%
Scarcity	$0.07	$0.17	$0.10	3.7%
Transmission Constraint Penalty Factor	$1.62	$3.01	$1.39	52.4%
Ancillary Service Redispatch Cost	$0.50	$1.33	$0.83	31.2%
Emergency Demand Response	$0.00	$0.00	$0.00	0.0%
PJM Administrative Cap	$0.00	$0.00	$0.00	0.0%
All Other	$1.10	$0.82	($0.28)	(10.6%)
Total Change	$31.08	$33.74	$2.66	100.0%

In order to understand the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach (Table 3-72 and Table 3-73) markup is the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-74), the 10 percent markup is removed from the cost-based offers of coal, gas, and oil units (adjusted markup).

The components of LMP are shown in Table 3-74, including markup using adjusted cost-based offers.

Table 3-74 Components of real-time (Adjusted) load-weighted average LMP: 2023 and 2024

	2023		2024		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$13.60	43.7%	$13.41	39.7%	(4.0%)
Positive Markup	$4.28	13.8%	$4.52	13.4%	(0.4%)
Coal	$4.49	14.4%	$4.09	12.1%	(2.3%)
Variable Maintenance	$2.31	7.4%	$3.18	9.4%	2.0%
Transmission Constraint Penalty Factor	$1.62	5.2%	$3.01	8.9%	3.7%
CO_2 Cost	$1.93	6.2%	$1.94	5.8%	(0.5%)
Variable Operations	$1.10	3.5%	$1.43	4.2%	0.7%
Ancillary Service Redispatch Cost	$0.50	1.6%	$1.33	3.9%	2.3%
Opportunity Cost Adder	$0.87	2.8%	$1.24	3.7%	0.9%
Oil	$0.31	1.0%	$1.08	3.2%	2.2%
Market-to-Market	$0.41	1.3%	$0.34	1.0%	(0.3%)
Increase Generation Differential	$0.13	0.4%	$0.24	0.7%	0.3%
LPA Rounding Difference	$0.40	1.3%	$0.18	0.5%	(0.8%)
Scarcity	$0.07	0.2%	$0.17	0.5%	0.3%
NA	$0.15	0.5%	$0.09	0.3%	(0.2%)
NO_x Cost	$0.51	1.6%	$0.09	0.3%	(1.4%)
Landfill Gas	$0.06	0.2%	$0.05	0.2%	(0.0%)
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%
Decrease Generation Differential	($0.01)	(0.0%)	($0.04)	(0.1%)	(0.1%)
Renewable Energy Credits	($0.07)	(0.2%)	($0.07)	(0.2%)	0.0%
Negative Markup	($1.61)	(5.2%)	($2.54)	(7.5%)	(2.4%)
Total	$31.08	100.0%	$33.74	100.0%	0.0%

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PJM implemented fast start pricing on September 1, 2021. The commitment cost related components of LMP are shown in Table 3-75 including markup using unadjusted cost-based offers for 2024. In 2024, 1.7 percent of the load-weighted average LMP was the result of commitment costs as a result of the fast start pricing rules that create prices inconsistent with fundamental LMP logic. The majority of the commitment costs in LMP were fuel costs in the no load component of offers for gas fired fast start units. The second largest component was maintenance costs.

Table 3-75 Commitment cost related components of real-time (Unadjusted) load-weighted average LMP: 2024

	Start Cost Components		No Load Components		Other Components		Total	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent
Gas	$0.00	0.0%	$0.35	1.0%	$13.06	38.7%	$13.41	39.7%
Coal	$0.00	0.0%	$0.00	0.0%	$4.09	12.1%	$4.09	12.1%
Postive Markup	$0.02	0.1%	$0.00	0.0%	$3.55	10.5%	$3.56	10.6%
Variable Maintenance	$0.13	0.4%	$0.01	0.0%	$3.03	9.0%	$3.18	9.4%
Transmission Constraint Penalty Factor	$0.00	0.0%	$0.00	0.0%	$3.01	8.9%	$3.01	8.9%
Ten Percent Adder	$0.01	0.0%	$0.03	0.1%	$1.96	5.8%	$2.00	5.9%
CO_2 Cost	$0.00	0.0%	$0.02	0.1%	$1.92	5.7%	$1.94	5.8%
Variable Operations	$0.00	0.0%	$0.00	0.0%	$1.43	4.2%	$1.43	4.2%
Ancillary Service Redispatch Cost	$0.00	0.0%	$0.00	0.0%	$1.33	3.9%	$1.33	3.9%
Opportunity Cost Adder	$0.00	0.0%	$0.00	0.0%	$1.24	3.7%	$1.24	3.7%
Oil	$0.00	0.0%	$0.02	0.1%	$1.05	3.1%	$1.08	3.2%
Market-to-Market	$0.00	0.0%	$0.00	0.0%	$0.34	1.0%	$0.34	1.0%
Increase Generation Differential	$0.00	0.0%	$0.00	0.0%	$0.24	0.7%	$0.24	0.7%
LPA Rounding Difference	$0.00	0.0%	$0.00	0.0%	$0.18	0.5%	$0.18	0.5%
Scarcity	$0.00	0.0%	$0.00	0.0%	$0.17	0.5%	$0.17	0.5%
NA	$0.00	0.0%	$0.00	0.0%	$0.09	0.3%	$0.09	0.3%
NO_x Cost	$0.00	0.0%	$0.00	0.0%	$0.08	0.2%	$0.09	0.3%
Landfill Gas	$0.00	0.0%	$0.00	0.0%	$0.05	0.2%	$0.05	0.2%
Other	$0.00	0.0%	$0.00	0.0%	$0.02	0.0%	$0.02	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
LPA-SCED Differential	$0.00	0.0%	$0.00	0.0%	($0.00)	(0.0%)	($0.00)	(0.0%)
Decrease Generation Differential	$0.00	0.0%	$0.00	0.0%	($0.04)	(0.1%)	($0.04)	(0.1%)
Renewable Energy Credits	$0.00	0.0%	$0.00	0.0%	($0.07)	(0.2%)	($0.07)	(0.2%)
Negative Markup	($0.00)	(0.0%)	($0.03)	(0.1%)	($3.55)	(10.5%)	($3.58)	(10.6%)
Total	$0.16	0.5%	$0.40	1.2%	$33.17	98.3%	$33.74	100.0%

The components of LMP for the dispatch run and the pricing run are shown in Table 3-76, including markup using unadjusted cost-based offers for 2024. 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 7.2 percent of the dispatch run LMP and 9.4 percent of the pricing run LMP.

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Table 3-76 Comparison of components of real-time (Unadjusted) load-weighted average LMP in the dispatch run and pricing run: 2024

	Dispatch		Pricing		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$12.57	40.1%	$13.41	39.7%	(0.4%)
Coal	$4.36	13.9%	$4.09	12.1%	(1.8%)
Positive Markup	$3.08	9.8%	$3.56	10.6%	0.7%
Variable Maintenance	$2.26	7.2%	$3.18	9.4%	2.2%
Transmission Constraint Penalty Factor	$2.90	9.3%	$3.01	8.9%	(0.3%)
Ten Percent Adder	$1.86	6.0%	$2.00	5.9%	(0.0%)
CO_2 Cost	$1.99	6.4%	$1.94	5.8%	(0.6%)
Variable Operations	$1.39	4.4%	$1.43	4.2%	(0.2%)
Ancillary Service Redispatch Cost	$0.93	3.0%	$1.33	3.9%	1.0%
Opportunity Cost Adder	$1.09	3.5%	$1.24	3.7%	0.2%
Oil	$0.97	3.1%	$1.08	3.2%	0.1%
Market-to-Market	$0.47	1.5%	$0.34	1.0%	(0.5%)
Increase Generation Differential	$0.18	0.6%	$0.24	0.7%	0.1%
LPA Rounding Difference	$0.26	0.8%	$0.18	0.5%	(0.3%)
Scarcity	$0.20	0.6%	$0.17	0.5%	(0.1%)
NA	$0.10	0.3%	$0.09	0.3%	(0.0%)
NO_x Cost	$0.08	0.2%	$0.09	0.3%	0.0%
Landfill Gas	$0.06	0.2%	$0.05	0.2%	(0.0%)
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%)
Decrease Generation Differential	($0.02)	(0.1%)	($0.04)	(0.1%)	(0.1%)
Renewable Energy Credits	($0.08)	(0.2%)	($0.07)	(0.2%)	0.0%
Negative Markup	($3.36)	(10.7%)	($3.58)	(10.6%)	0.1%
Total	$31.31	100.0%	$33.74	100.0%	0.0%

The components of the total cost of real-time load ($ million) are shown in Table 3-77, including markup using unadjusted cost-based offers. The components of the total cost of real-time load are shown in Table 3-78, including markup using adjusted cost-based offers. In 2024, the cost of real-time load increased by $2,988.1 million or 12.7 percent. Of the $26,455.7 million in the total cost of real-time load in 2024, $10,515.7 million is due to the cost of gas. Of the $23,467.7 million attributable to the cost of real-time load in 2023, $10,265.3 million is due to the cost of gas.

Table 3-79 shows the components of the increase in the cost of real-time load from 2023 to 2024. In 2024, the cost of real-time load increased $2,988.1 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 $964.1, 32.3 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) increased the real-time cost of load by $54.3 million, 1.8 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 $274.2 million, 9.2 percent of the increase in the cost of real time load. The scarcity component increased the cost of real-time load by $79.9 million, 2.7 percent of the increase in the cost of real-time load. The transmission constraint penalty factor increased the cost of real-time load by $1,139.1 million, 38.1 percent. The ancillary service redispatch cost, the opportunity cost of reduced marginal generation to meet reserve requirements, increased the cost of real-time load by $665.16, 22.3 percent of the cost of real time load.

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Table 3-77 Components of the cost of real-time (Unadjusted) load: 2023 and 2024

	Contribution to Real Time Cost of Load ($Million)			
Element	2023	2024	Change	Percent
Gas	$10,265.3	$10,515.7	$250.5	8.4%
Coal	$3,389.7	$3,205.4	($184.3)	(6.2%)
Positive Markup	$2,485.4	$2,795.2	$309.7	10.4%
Variable Maintenance	$1,744.8	$2,489.9	$745.2	24.9%
Transmission Constraint Penalty Factor	$1,221.9	$2,361.0	$1,139.1	38.1%
Ten Percent Adder	$1,473.8	$1,568.9	$95.1	3.2%
CO_2 Cost	$1,458.5	$1,521.8	$63.3	2.1%
Variable Operations	$829.0	$1,122.9	$293.9	9.8%
Ancillary Service Redispatch Cost	$376.1	$1,041.3	$665.2	22.3%
Opportunity Cost Adder	$656.4	$970.8	$314.4	10.5%
Oil	$235.6	$843.8	$608.3	20.4%
Market-to-Market	$307.4	$266.3	($41.1)	(1.4%)
Increase Generation Differential	$98.0	$185.7	$87.7	2.9%
LPA Rounding Difference	$305.2	$141.5	($163.7)	(5.5%)
Scarcity	$51.1	$131.0	$79.9	2.7%
NA	$115.3	$71.2	($44.1)	(1.5%)
NO_x Cost	$384.8	$67.1	($317.7)	(10.6%)
Landfill Gas	$46.4	$42.2	($4.2)	(0.1%)
Other	$16.5	$13.2	($3.4)	(0.1%)
SO_2 Cost	$0.3	$0.2	($0.0)	(0.0%)
LPA-SCED Differential	($0.0)	($0.0)	$0.0	0.0%
Decrease Generation Differential	($8.9)	($33.1)	($24.1)	(0.8%)
Renewable Energy Credits	($50.4)	($56.1)	($5.7)	(0.2%)
Negative Markup	($1,934.6)	($2,810.4)	($875.7)	(29.3%)
Total	$23,467.7	$26,455.7	$2,988.1	100.0%

Table 3-78 Components of the (Adjusted) cost of real-time load: 2023 and 2024

	Contribution to Real Time Cost of Load ($Million)			
Element	2023	2024	Change	Percent
Gas	$10,265.3	$10,515.7	$250.5	8.4%
Positive Markup	$3,230.3	$3,541.1	$310.8	10.4%
Coal	$3,389.7	$3,205.4	($184.3)	(6.2%)
Variable Maintenance	$1,744.8	$2,489.9	$745.2	24.9%
Transmission Constraint Penalty Factor	$1,221.9	$2,361.0	$1,139.1	38.1%
CO_2 Cost	$1,458.5	$1,521.8	$63.3	2.1%
Variable Operations	$829.0	$1,122.9	$293.9	9.8%
Ancillary Service Redispatch Cost	$376.1	$1,041.3	$665.2	22.3%
Opportunity Cost Adder	$656.4	$970.8	$314.4	10.5%
Oil	$235.6	$843.8	$608.3	20.4%
Market-to-Market	$307.4	$266.3	($41.1)	(1.4%)
Increase Generation Differential	$98.0	$185.7	$87.7	2.9%
LPA Rounding Difference	$305.2	$141.5	($163.7)	(5.5%)
Scarcity	$51.1	$131.0	$79.9	2.7%
NA	$115.2	$71.1	($44.1)	(1.5%)
NO_x Cost	$384.8	$67.1	($317.7)	(10.6%)
Landfill Gas	$46.4	$42.2	($4.2)	(0.1%)
Other	$16.5	$13.2	($3.4)	(0.1%)
Ten Percent Adder	$7.0	$6.6	($0.4)	(0.0%)
SO_2 Cost	$0.3	$0.2	($0.0)	(0.0%)
LPA-SCED Differential	($0.0)	($0.0)	$0.0	0.0%
Decrease Generation Differential	($8.9)	($33.1)	($24.1)	(0.8%)
Renewable Energy Credits	($50.4)	($56.1)	($5.7)	(0.2%)
Negative Markup	($1,212.7)	($1,994.0)	($781.3)	(26.1%)
Total	$23,467.7	$26,455.7	$2,988.1	100.0%

Table 3-79 Components of Change in the cost of real-time load: 2023 and 2024

	($ Million)			Percent of Total
Component	2023	2024	Change	Change
Fuel and Consumables	$14,765.9	$15,730.1	$964.1	32.3%
Emission Related	$2,449.7	$2,503.9	$54.3	1.8%
Market Power Related	$3,769.4	$4,043.6	$274.2	9.2%
Scarcity	$51.1	$131.0	$79.9	2.7%
Transmission Constraint Penalty Factor	$1,221.9	$2,361.0	$1,139.1	38.1%
Ancillary Service Redispatch Cost	$376.1	$1,041.3	$665.2	22.3%
Emergency Demand Response	$0.0	$0.0	$0.0	0.0%
PJM Administrative Cap	$0.0	$0.0	$0.0	0.0%
All Other	$833.6	$644.8	($188.7)	(6.3%)
Total Change	$23,467.7	$26,455.7	$2,988.1	100.0%

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Shortage

PJM's real-time energy market experienced five-minute shortage pricing for one or more reserve products for 39 unique five-minute intervals across 17 days in 2024. 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 2024, there were 39 unique five-minute intervals with real-time shortage pricing in the pricing run for one or more reserve products, and 35unique intervals with real-time shortage pricing in the dispatch run for one or more reserve products.

Emergency Procedures

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.

Table 3-80 provides a description of PJM declared emergency procedures.[115] [116] [117] [118]

Table 3-80 Description of emergency procedures

Emergency Procedure	Purpose
Cold Weather Alert	To prepare personnel and facilities for extreme cold weather conditions, generally when forecast weather conditions approach minimum or temperatures fall below ten degrees Fahrenheit.
Hot Weather Alert	To prepare personnel and facilities for extreme hot and/or humid weather conditions, generally when forecast temperatures exceed 90 degrees with high humidity.
Maximum Emergency Generation Alert	To provide an early alert at least one day prior to the operating day that system conditions may require the use of the PJM emergency procedures and resources must be able to increase generation above the maximum economic level of their offers.
Primary Reserve Alert	To alert members of a projected shortage of primary reserve for a future period. It is implemented when estimated primary reserve is less than the forecast requirement.
Voltage Reduction Alert	To alert members that a voltage reduction may be required during a future critical period. It is implemented when estimated reserve capacity is less than forecasted synchronized reserve requirement.
Pre-Emergency Load Management Reduction Action	To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time before declaring emergency load management reductions
Emergency Mandatory Load Management Reduction Action	To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time to provide additional load relief, generally declared simultaneously with NERC Energy Emergency Alert Level 2 (EEA2)
Primary Reserve Warning	To warn members that available primary reserve is less than required and present operations are becoming critical. It is implemented when available primary reserve is less than the primary reserve requirement but greater than the synchronized reserve requirement.
Maximum Emergency Generation Action	To provide real time notice to increase generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the maximum economic level.
Voltage Reduction Warning & Reduction of Non-Critical Plant Load	To warn members that actual synchronized reserves are less than the synchronized reserve requirement and that voltage reduction may be required.
Deploy All Resources Action	For emergency events that do not evolve over time, but rather develop rapidly and without prior warning, PJM issues this action to instruct all generation resources to be online immediately and to all load management resources to reduce load immediately.
Manual Load Dump Warning	To warn members of the critical condition of present operations that may require manually dumping load. Issued when available primary reserve capacity is less than the largest operating generator or the loss of a transmission facility jeopardizes reliable operations after all other possible measures are taken to increase reserve.
Voltage Reduction Action	To reduce load to provide sufficient reserve capacity to maintain tie flow schedules and preserve limited energy sources. It is implemented when load relief is needed to maintain tie schedules.
Manual Load Dump Action	To provide load relief when all other possible means of supplying internal PJM RTO load have been used to prevent a catastrophe within the PJM RTO or to maintain tie schedules so as not to jeopardize the reliability of the other interconnected regions.
Post Contingency Local Load Relief Warning	To warn transmission owners of the possibility of load shed in their area.
Non-Market Post Contingency Local Load Relief Warning	To warn transmission owners of the of possibility load shed in their area for non-market facilities.

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

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Table 3-81 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in 2024. Events in Table 3-81 can span multiple days, but only the first day is shown.

Table 3-81 Starting days of declared emergency alerts, warnings and actions: January through December, 2024

Date	Cold Weather Alert	Hot Weather Alert	Maximum Emergency Generation Alert	Primary Reserve Alert	Voltage Reduction Alert	Primary Reserve Warning	Voltage Reduction Warning and Reduction of Non-Critical Plant Load	Maximum Emergency Generation Action	Pre-Emergency Mandatory Load Management Reduction	Emergency Mandatory Load Management Reduction	Voltage Reduction	Manual Load Dump Warning	Manual Load Dump Action	Load Shed Directive
14-Jan-2024	Western													
19-Jan-2024	Western													
22-May-2024		Mid-Atlantic												
13-Jun-2024		PJM RTO												
14-Jun-2024		Mid-Atlantic, Southern												
16-Jun-2024		Western												
17-Jun-2024		PJM RTO												
24-Jun-2024		Mid-Atlantic, Southern												
25-Jun-2024		PJM RTO												
26-Jun-2024		Mid-Atlantic, Southern												
08-Jul-2024		PJM RTO												
09-Jul-2024		Mid-Atlantic, Southern												
10-Jul-2024		Mid-Atlantic, Southern												
14-Jul-2024		PJM RTO												
15-Jul-2024		PJM RTO												
16-Jul-2024		PJM RTO												
17-Jul-2024		Mid-Atlantic, Southern												
31-Jul-2024		Mid-Atlantic, Southern												
02-Aug-2024		Mid-Atlantic, Southern												
05-Aug-2024		Mid-Atlantic, Southern												
26-Aug-2024		Western												
27-Aug-2024		PJM RTO												
28-Aug-2024		PJM RTO												
12-Dec-2024	COMED													
13-Dec-2024	COMED													

Table 3-82 shows the number of days for which emergency alerts, warnings, and actions were declared by PJM in 2023 and 2024. In 2024, there were zero days with emergency actions and shortages that triggered Performance Assessment Intervals (PAI).[119]

Table 3-82 Number of days for which PJM declared events: 2023 and 2024

	Number of days for which events declared	
Event Type	2023	2024
Cold Weather Alert	3	10
Hot Weather Alert	21	28
Maximum Emergency Generation Alert	3	2
Primary Reserve Alert	0	0
Voltage Reduction Alert	0	0
Primary Reserve Warning	0	0
Voltage Reduction Warning	0	0
Pre Emergency Mandatory Load Management Reduction Action	0	0
Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time)	0	0
Maximum Emergency Action	0	0
Emergency Energy Bids Requested	0	0
Voltage Reduction Action	0	0
Shortage Pricing	46	17
Energy export recalls from PJM capacity resources	0	0

119 A PAI is triggered when PJM takes an emergency action and there is a shortage of primary reserves. See 184 FERC ¶ 61,058 (2023).

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Figure 3-51 shows the number of days for which weather and capacity emergency alerts were issued in PJM in 2020 through 2024.

Figure 3-51 Number of days for which emergency alerts declared: 2020 through 2024

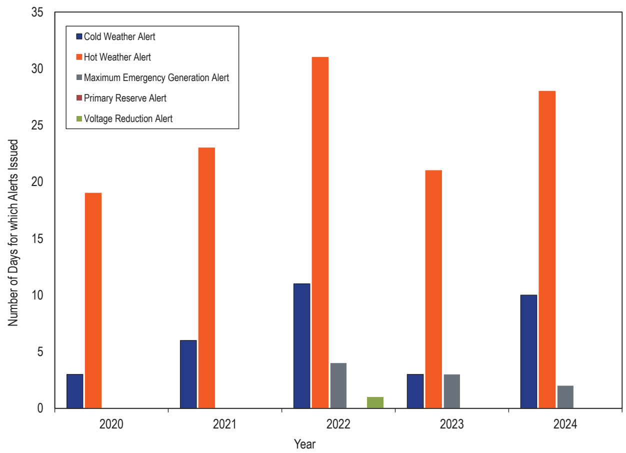
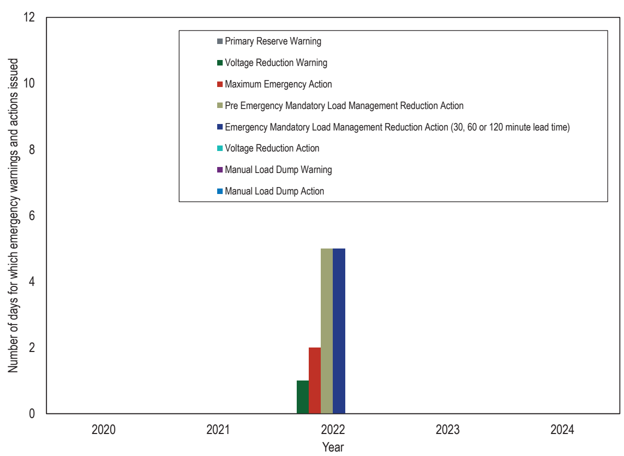


Figure 3-52 shows the number of days for which emergency warnings and actions were declared in PJM in 2020 through 2024.

Figure 3-52 Declared emergency warnings and actions: 2020 through 2024



In 2024, PJM issued 32 Non-Market Post Contingency Local Load Relief warnings and 314 Post Contingency Local Load Relief warnings. These warnings notify transmission owners of the possibility of disconnecting load in their area, either via manual load dumping by non-market load or via load shed.

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.[120] 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

120 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.

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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 3-83 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 2024, there were 6 five minute intervals using an RT SCED solution with an apparently violated power balance constraint. PJM ignored (relaxed) the power balance constraints in 2024.

Table 3-83 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

Shortage and Shortage Pricing

In electricity markets, shortage means that demand, including reserve requirements, is nearing the limits of the currently available capacity of the system. Shortage pricing is a mechanism for signaling scarcity conditions through higher energy prices. Under the PJM rules that were in place through September 30, 2012, shortage pricing resulted from the exercise of aggregate market power by individual generation owners for specific units when the system was close to its available capacity. But 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 lower real-time reserves than the target level.

In 2024, there were 39 five-minute intervals with real-time shortage pricing for one or more reserve products that occurred on 17 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.[121] 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 match the frequency of pricing at five minutes, which reduced the frequency of unpriced shortage solutions.

Prior to September 1, 2021, the reserves calculated in the LPC solution, and the reserves calculated in the reference RT SCED case used by the LPC solution were the same. With the implementation of fast start pricing on September 1, 2021, shortage pricing is now

121 *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).

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triggered by the pricing run in LPC.[122] 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 once in 2024.

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.[123]

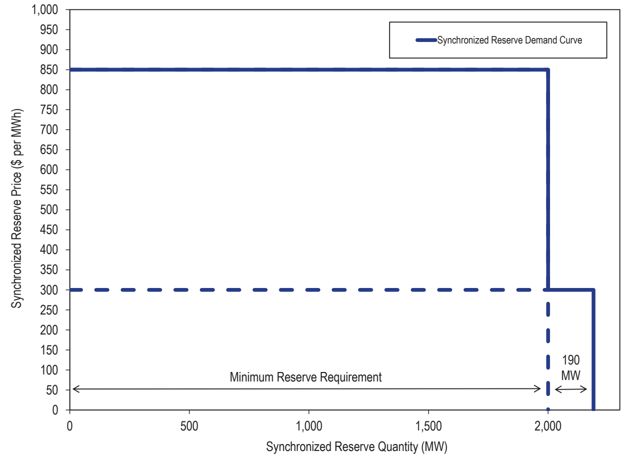
Operating Reserve Demand Curves

Shortage pricing in the PJM Energy Market can occur in either the day-ahead or the real-time market for any of five reserves requirements: RTO Synchronized Reserves, Subzone Synchronized Reserves, RTO Primary Reserves, Subzone Primary Reserves, and 30-Minute Reserves. Each requirement is modelled in the market clearing engines as a demand curve priced at $850 per MWh up to the minimum reserve requirement (MRR) and at $300 per MWh for additional reserves of at least 190 MW.[124] [125] 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, which causes the administrative price on the ORDC to determine the marginal cost of the reserve shortage. Because an additional MW of energy on the margin would require another MW of reserves shortage, the administrative marginal cost of reserves is added to LMP.

Shortage Pricing and Energy Price Formation

The current operating reserve demand curves (ORDC) in PJM define an administrative price for estimated reserves (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 3-53 drops to a zero price for quantities above the extended reserve requirement.

Figure 3-53 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

122 *See* PJM Operating Agreement, Schedule 1, Section 2.5.1(a).
123 *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).
124 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3.3 Reserve Demand Curves and Penalty Factors, Rev. 133 (Dec. 17, 2024).
125 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3 Reserve Requirement Determination, Rev. 133 (Dec. 17, 2024).

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that the effect of reserve constraints on prices can be additive.

The effect of the reserve constraints on pricing depends on the constraint shadow price. In general, the shadow price of a constraint is the change in the total production cost (the objective function of the market dispatch software) if that constraint limit were increased 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 3-84 shows six example scenarios, under the current ORDCs, with combinations of energy offers, reserve shortage penalty factors and transmission constraint penalty factors that can add up to produce high LMPs at sample pnodes in the MAD Reserve Subzone and outside the MAD Reserve Subzone.

Scenario A shows a simple shortage in the RTO Reserve Zone. In scenario B, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones that results in a $1,700 per MWh reserve shortage penalty in the RTO Zone LMP and a $3,400 per MWh reserve shortage penalty in the MAD Zone LMP. The marginal resource for energy is in the RTO Zone. 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.[126]

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 violated transmission penalty factor affects the LMP at a pnode is directly proportional to the pnode's distribution factor (dfax) with respect to that constraint. In addition, the LMP at a pnode includes a loss component calculated as the product of the

126 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.

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marginal loss factor and the uncapped system marginal price.

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

Scenario	Marginal Unit Offer Price	Synchronized Reserve Penalty Factor RTO	Synchronized Reserve Penalty Factor MAD	Primary Reserve Penalty Factor RTO	Primary Reserve Penalty Factor MAD	30 Minute Reserve Penalty Factor RTO	Transmission Constraint Penalty Factor in SMP	System Marginal Price RTO Marginal	System Marginal Price MAD Marginal	Transmission Constraint Penalty Factor in CLMP	Total LMP RTO Marginal	Total LMP 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

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. This results in a discrepancy between the operational need during a spinning event, and the RT SCED solutions.

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 for their intended purpose. Currently, RT SCED has the ability to back down units during events to create available reserves, which counteracts PJM's recovery effort. 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, shortage pricing was triggered during the spin events on January 29, 2024, June 3, 2024, and July 8, 2024. The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirements by the amount of the reserves deployed.

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 in 2024 failed to result in reliably timely responses, defined to be within 10 minutes. For units that could receive an electronig signal, PJM's instruction to reserves was to ignore the dispatch signals sent by RT SCED and to instead continue to 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, then additional minutes could also be lost switching to manual control. The end result was that resources started responding minutes into an event, even when everything went well.[127] 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 did resolve the communications issues for all resources. Significant communications issue remain to be resolved.

127 See the *2024 Annual 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 2024

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.

For reliability reasons, and to maintain reserves to comply with NERC standards, reserves are considered short if the quantity (MW) of reserves dispatched by RT SCED for a five minute interval is less than the minimum reserve requirement (MRR). To trigger shortage pricing, reserves are considered short if the quantity (MW) of reserves dispatched by RT SCED for a five minute interval is less than the extended reserve requirement.

Until June 2, 2021, PJM generally solved one RT SCED case with three solutions per case, for each five minute target time.[128] [129] On June 3, 2021, PJM updated RT SCED to solve two additional scenarios, or a total of five solutions per case. In 2021, the frequency with which RT SCED solutions were approved increased to one solution per five minute interval. This approval frequency increased the proportion of approved SCED solutions that are reflected in LMPs. However, the process of selecting the SCED solution to approve, among the solutions available to PJM operators, is subjective and is not based on clearly defined criteria. The criteria are especially important when only some of the SCED solutions reflect shortage pricing, and the rest of the solutions do not.

The MMU analyzed the target times for which one or more RT SCED case solutions indicated a shortage of one or more reserve products. Table 3-85 shows, in 2023 and 2024, the total number of target times, the number of target times for which at least one RT SCED solution showed a shortage of reserves, the number of target times for which more than one RT SCED solution showed a shortage of reserves, and the number of five-minute pricing intervals for which the LPC solution showed a shortage of reserves. Each execution of RT SCED produces five solutions, using five different levels of load bias. Table 3-85 shows that, in 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 2023, there were 4,307 target times, or 4.1 percent of all five-minute target times, that had at least one RT SCED solution showing a shortage of reserves, and 1,452 target times, or 1.4 percent of all five-minute target times, that had more than one RT SCED solution showing a shortage of reserves.

Table 3-85 Real-time monthly five minute SCED target times and pricing intervals with shortage: 2023 through 2024

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
2023	Jan	8,928	187	2.1%	63	0.7%	3	1.6%
2023	Feb	8,064	89	1.1%	16	0.2%	0	0.0%
2023	Mar	8,916	75	0.8%	22	0.2%	0	0.0%
2023	Apr	8,640	444	5.1%	146	1.7%	0	0.0%
2023	May	8,928	948	10.6%	396	4.4%	35	3.7%
2023	Jun	8,640	268	3.1%	84	1.0%	0	0.0%
2023	Jul	8,928	219	2.5%	60	0.7%	1	0.5%
2023	Aug	8,928	115	1.3%	24	0.3%	0	0.0%
2023	Sep	8,640	130	1.5%	34	0.4%	2	1.5%
2023	Oct	8,928	862	9.7%	303	3.4%	3	0.3%
2023	Nov	8,652	466	5.4%	157	1.8%	0	0.0%
2023	Dec	8,928	504	5.6%	147	1.6%	2	0.4%
2023	Total	105,120	4,307	4.1%	1,452	1.4%	46	1.1%
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%

128 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.

129 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.

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As shown in Table 3-85, 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 2023, there were 1,452 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 46 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 2024, there was no shortage pricing in the day-ahead energy market.

In May 2023, PJM increased reserve requirements in response to poor reserve performance. While the intervals listed in this section were short of their target requirements, it is important to note that 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.

There were 39 unique real-time five minute intervals with shortage pricing for one or more reserve products in 2024, compared to 46 intervals in 2023. As of the end of 2024, there has never been shortage pricing in the day-ahead market. PJM implemented fast start pricing on September 1, 2021. Fast start pricing can result in differences in reserve shortages between the dispatch run and the pricing run. In 2024, there were 39 five minute intervals with shortage pricing in the pricing run for one or more reserve products, and 35 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.

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 two intervals with shortage pricing in the pricing run due to synchronized reserve shortage in 2024. Table 3-86 shows that two intervals were short of synchronized reserves in both the pricing run and the dispatch run. Both intervals were also short primary reserves in the pricing run and the dispatch run.

In the MAD Reserve Subzone, there were zero intervals with shortage pricing in the pricing run due to a synchronized reserve shortage in 2024.

Table 3-87 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the RTO Reserve Zone during the 36 intervals with shortage pricing in the pricing run due to primary reserve shortage in 2024. Table 3-87 shows that 32 of the 36 intervals were short of primary reserves in both the pricing run and the dispatch run. The intervals on May 21, October 16, and December 6 were not short in the dispatch run. The intervals on January 29, June 3, and July 8 occurred during synchronized reserve events.

Table 3-88 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the MAD Reserve Subzone during the nine intervals with shortage pricing in the pricing run due to primary reserve shortage in 2024. Table 3-88 shows that all nine of the intervals were short of primary reserves in both the dispatch run and the pricing run, and that one of the intervals had different capped prices in the dispatch and pricing runs. The one interval on June 3 occurred during a synchronized reserve event.

In the RTO Reserve Zone, there were zero intervals with shortage pricing in the pricing run due to a 30-minute reserve shortage in 2024.

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.[130] 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.[131] The system marginal price cap should be included in the PJM tariff and Operating Agreement.

Table 3-86 Real-time RTO synchronized reserve shortage intervals: 2024

	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)
03-Jun-24 19:00	2,524.3	2,222.8	301.5	$1,700.00	$1,700.00	2,524.3	2,222.8	301.5	$1,700.00	$1,700.00
28-Jul-24 17:30	2,515.1	2,325.1	190.0	$1,552.06	$1,552.06	2,515.1	2,325.1	190.0	$1,552.06	$1,552.06

130 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.
131 OA Schedule 1, Section 3.2.3A(d) and Section 3.2.3A.001(c).

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Table 3-87 Real-time RTO primary reserve shortage intervals: 2024

	Pricing Run					Dispatch Run				
Interval (EPT)	RTO Extended Primary Reserve Requirement (MW)	Total RTO Primary Reserves (MW)	RTO Primary Reserve Shortage (MW)	Uncapped RTO Primary Reserve Clearing Price ($/MWh)	Capped RTO Primary Reserve Clearing Price ($/MWh)	RTO Extended Primary Reserve Requirement (MW)	Total RTO Primary Reserves (MW)	RTO Primary Reserve Shortage (MW)	Uncapped RTO Primary Reserve Clearing Price ($/MWh)	Capped RTO Primary Reserve Clearing Price ($/MWh)
20-Jan-24 17:40	3,530.3	3,483.9	46.4	$300.00	$300.00	3,530.3	3,483.9	46.4	$300.00	$300.00
20-Jan-24 17:50	3,530.3	3,340.4	190.0	$544.78	$544.78	3,530.3	3,340.4	190.0	$544.78	$544.78
20-Jan-24 17:55	3,530.3	3,340.4	190.0	$544.78	$544.78	3,530.3	3,340.4	190.0	$544.78	$544.78
22-Jan-24 06:45	3,536.2	3,261.3	274.9	$850.00	$850.00	3,536.2	3,261.3	274.9	$850.00	$850.00
22-Jan-24 06:50	3,536.2	3,346.2	190.0	$647.02	$647.02	3,536.2	3,346.2	190.0	$647.02	$647.02
29-Jan-24 12:05	3,507.9	3,226.8	281.1	$850.00	$850.00	3,507.9	3,226.8	281.1	$850.00	$850.00
29-Jan-24 12:10	3,475.2	3,207.1	268.1	$850.00	$850.00	3,475.2	3,207.1	268.1	$850.00	$850.00
10-Mar-24 19:20	3,664.9	3,495.7	169.2	$300.00	$300.00	3,664.9	3,495.7	169.2	$300.00	$300.00
10-Mar-24 19:25	3,664.9	2,912.5	752.4	$850.00	$850.00	3,664.9	2,912.5	752.4	$850.00	$850.00
10-Mar-24 19:30	3,664.9	3,297.6	367.3	$850.00	$850.00	3,664.9	3,297.6	367.3	$850.00	$850.00
10-Mar-24 19:35	3,664.9	2,730.1	934.8	$850.00	$850.00	3,664.9	2,730.1	934.8	$850.00	$850.00
10-Mar-24 19:40	3,664.9	3,103.9	561.0	$850.00	$850.00	3,664.9	3,103.9	561.0	$850.00	$850.00
10-Mar-24 19:45	3,664.9	2,836.3	828.6	$850.00	$850.00	3,664.9	2,836.3	828.6	$850.00	$850.00
10-Mar-24 19:50	3,664.9	3,205.6	459.3	$850.00	$850.00	3,664.9	3,213.6	451.3	$850.00	$850.00
10-Mar-24 19:55	3,664.9	3,343.9	321.0	$850.00	$850.00	3,664.9	3,351.9	313.0	$850.00	$850.00
18-Mar-24 20:00	3,664.9	3,554.0	110.9	$300.00	$300.00	3,664.9	3,554.0	110.9	$300.00	$300.00
14-Apr-24 20:00	2,822.5	2,790.1	32.4	$300.00	$300.00	2,822.5	2,790.1	32.4	$300.00	$300.00
14-Apr-24 20:20	2,822.5	2,785.3	37.2	$300.00	$300.00	2,822.5	2,785.3	37.2	$300.00	$300.00
21-May-24 18:10	3,664.9	3,635.7	29.2	$300.00	$300.00	3,664.9	3,664.9	0.0	$236.45	$236.45
03-Jun-24 18:55	3,695.7	3,249.7	446.0	$850.00	$850.00	3,695.7	3,249.7	446.0	$850.00	$850.00
03-Jun-24 19:00	3,691.4	2,566.8	1,124.6	$850.00	$850.00	3,691.4	2,566.8	1124.6	$850.00	$850.00
08-Jul-24 18:00	3,677.6	3,576.3	101.2	$300.00	$300.00	3,677.6	3,576.3	101.2	$300.00	$300.00
28-Jul-24 17:25	3,677.6	3,164.0	513.6	$850.00	$850.00	3,677.6	3,164.0	513.6	$850.00	$850.00
28-Jul-24 17:30	3,677.6	2,802.9	874.7	$850.00	$850.00	3,677.6	2,802.9	874.7	$850.00	$850.00
04-Sep-24 06:30	3,677.6	3,593.5	84.1	$300.00	$300.00	3,677.6	3,593.5	84.1	$300.00	$300.00
04-Sep-24 06:35	3,677.6	3,602.0	75.5	$300.00	$300.00	3,677.6	3,602.0	75.5	$300.00	$300.00
14-Oct-24 19:00	3,896.4	3,826.3	70.0	$300.00	$300.00	3,896.4	3,826.3	70.0	$300.00	$300.00
15-Oct-24 18:45	3,887.5	3,887.5	0.0	$300.00	$300.00	3,887.5	3,887.5	0.0	$300.00	$300.00
15-Oct-24 18:50	3,889.5	3,889.5	0.0	$300.00	$300.00	3,889.5	3,889.5	0.0	$300.00	$300.00
15-Oct-24 18:55	3,889.5	3,889.5	0.0	$300.00	$300.00	3,889.5	3,889.5	0.0	$300.00	$300.00
16-Oct-24 19:05	2,668.4	2,644.6	23.8	$300.00	$300.00	2,668.4	2,668.5	0.0	$170.75	$170.75
16-Oct-24 19:10	2,668.4	2,644.6	23.8	$300.00	$300.00	2,668.4	2,668.5	0.0	$170.75	$170.75
22-Nov-24 01:05	3,677.6	3,465.6	212.0	$850.00	$850.00	3,677.6	3,465.6	212.0	$850.00	$850.00
06-Dec-24 07:25	3,716.8	3,676.9	39.9	$300.00	$300.00	3,716.8	3,716.8	0.0	$294.45	$294.45
06-Dec-24 17:35	3,677.6	3,602.6	75.0	$300.00	$300.00	3,677.6	3,602.6	75.0	$300.00	$300.00
06-Dec-24 17:40	3,677.6	3,602.6	75.0	$300.00	$300.00	3,677.6	3,602.6	75.0	$300.00	$300.00

Table 3-88 Real-time MAD primary reserve shortage intervals: 2024

	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)
20-Jan-24 17:35	2,740.0	2,550.0	190.0	$307.50	$307.50	2,740.0	2,550.0	190.0	$307.50	$307.50
20-Jan-24 17:50	2,740.0	2,550.0	190.0	$865.68	$865.68	2,740.0	2,550.0	190.0	$865.68	$865.68
20-Jan-24 17:55	2,740.0	2,550.0	190.0	$865.68	$865.68	2,740.0	2,550.0	190.0	$865.68	$865.68
21-Jan-24 17:45	2,710.0	2,657.1	52.9	$306.26	$306.26	2,710.0	2,644.5	65.6	$300.38	$300.38
22-Jan-24 06:45	2,764.0	2,574.0	190.0	$1,161.19	$1,161.19	2,764.0	2,574.0	190.0	$1,161.19	$1,161.19
22-Jan-24 06:50	2,764.0	2,574.0	190.0	$957.95	$957.95	2,764.0	2,574.0	190.0	$957.95	$957.95
22-Jan-24 06:55	2,764.0	2,574.0	190.0	$526.19	$526.19	2,764.0	2,574.0	190.0	$526.19	$526.19
03-Jun-24 19:00	2,579.5	2,566.8	12.7	$1,150.00	$1,150.00	2,579.5	2,566.8	12.7	$1,150.00	$1,150.00
14-Oct-24 19:00	3,896.3	3,826.4	70.0	$600.00	$600.00	3,896.3	3,826.4	70.0	$600.00	$600.00

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System Marginal Price Cap

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

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

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

Table 3-89 shows the number of five minute intervals in the real-time market where the SMP was capped for each year since 2019. In 2024, there were zero five minute intervals in the real-time market where the SMP was capped.

Table 3-89 Number of five minute intervals with capped SMP: 2018 through 2024

Year	Number of Five Minute Intervals with capped SMP
2018	0
2019	1
2020	1
2021	2
2022	51
2023	1
2024	0

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.[132] 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

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

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the actions PJM dispatchers can take when generators do not follow dispatch.

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

PJM deselects specific units from providing reserves, and overrides the dispatch signal to certain units to set the dispatch signal equal to actual resource output. These manual interventions are, at best, rough approximations of the capability of generators and result in an inaccurate measurement of reserves.

Competitive Assessment

Market Structure

Market Concentration

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

The HHI is not a definitive measure of structural market power. It is possible to have pivotal suppliers even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI.

The HHI may not accurately capture market power issues in situations where, for example, there is moderate concentration in all on line resources but there is a high level of concentration in resources needed to meet increases in load. A pivotal supplier test is required to accurately measure the ability of incremental resources to exercise market power.

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.[133]

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 2024, although there are issues with the application of market power mitigation for resources whose owners fail the TPS test that permit local market power to be exercised even when mitigation rules are

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

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 2024 was unconcentrated on average (Table 3-90).[134] 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.

Table 3-90 Real-time hourly aggregate energy market HHI: 2023 and 2024

HHI Statistic	Hourly Market HHI (2023)	Hourly Market HHI (2024)
Average	690	714
Minimum	528	553
Maximum	949	983
Highest market share (One hour)	26%	26%
Average of the highest hourly market share	18%	18%
# Hours	8,760	8,784
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-91 includes HHI values by supply curve segment, including base, intermediate and peaking plants in 2023 and 2024. On average, ownership in the baseload segment was unconcentrated, in the intermediate segment was moderately concentrated, and in the peaking segment was highly concentrated.[135] High concentration levels increase the probability that a generation owner will be pivotal in the aggregate market.

Table 3-91 Real-time hourly energy market HHI by generation segment: 2023 and 2024

	2023			2024		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	577	706	971	573	727	1015
Intermediate	679	1481	7085	438	1586	5992
Peak	812	6240	10000	829	6293	10000

Figure 3-54 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in 2024.[136]

Figure 3-54 Real-time ICAP distribution by fuel and segment: 2024[137]

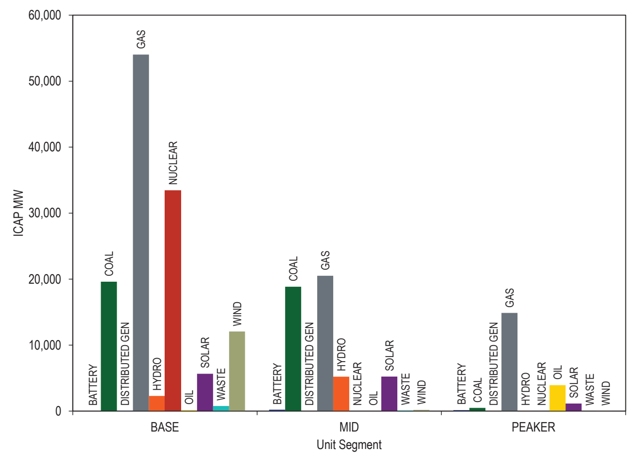

Figure 3-55 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking from 2014 through 2024. Figure 3-55 shows that the total ICAP of coal fired units in PJM classified as baseload generally decreased from 2014 through 2024, while the total ICAP 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.

134 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.

135 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.

136 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.

137 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).

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Figure 3-55 Real-time annual gas and coal unit segment classification: 2014 through 2024

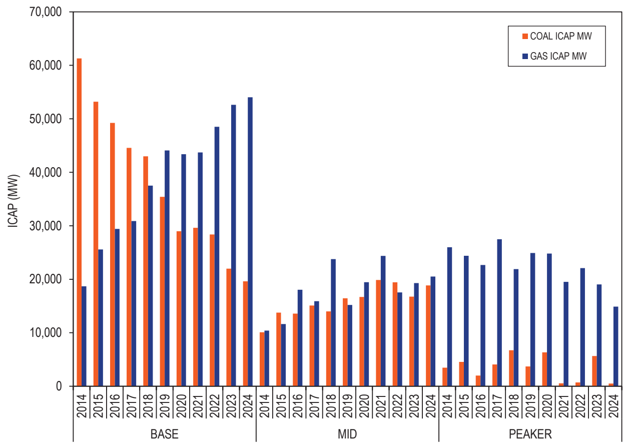
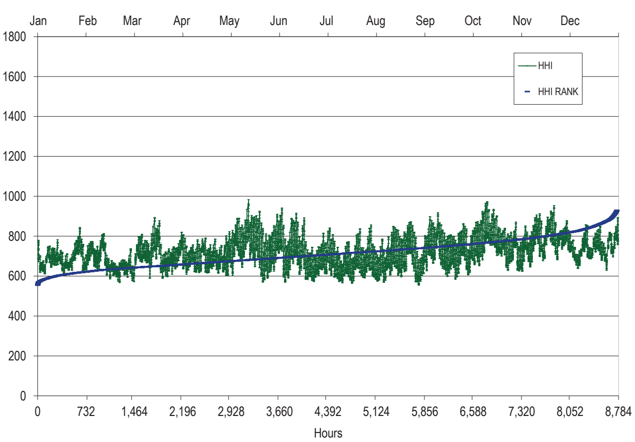


Figure 3-56 presents the hourly HHI values in chronological order and an HHI duration curve for 2024.

Figure 3-56 Real-time hourly aggregate energy market HHI: 2024



Market Based Rates

Participation in the PJM market using offers that exceed costs requires market based rate authority approved by FERC.[138] FERC reviews the market based rate authority of PJM market sellers on a triennial schedule to ensure that market sellers do not have market power or that market power is appropriately mitigated. The entire PJM region is included in the Northeast Region for purposes of the triennial review schedule. Triennial filings by utilities with market based rates authorizations must include a market power analysis or a statement that market power has been adequately mitigated under the PJM market rules. Based on Order No. 861, sellers may, in lieu of filing a market power analysis, rely on a rebuttable presumption that market monitoring and market power mitigation are sufficient to ensure competitive market outcomes.[139]

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 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.[140] In 2021, FERC issued orders requiring review of the adequacy of the market power mitigation rules and their implementation in the

138 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).

139 *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").

140 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).

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capacity and energy markets.[141] [142] FERC addressed the capacity market Market Seller Offer Cap later in 2021.[143]

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."[144] [145]

FERC applies tests set forth in the 1996 Merger Policy Statement.[146] [147] 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.[148] Following the 1992 Guidelines, FERC applies a five step framework, which includes: defining the market; analyzing market concentration; analyzing mitigative effects of new entry; assessing efficiency gains; and assessing viability of the parties without a merger. FERC also evaluates a Competitive Analysis Screen.

The MMU reviews proposed mergers and acquisitions based on analysis of the impact of the merger or acquisition on market power given actual PJM market conditions. The analysis includes use of the three pivotal supplier test results in the real-time energy market. The MMU's review ensures that mergers are evaluated based on their impact on local market power in the PJM energy market using actual observed market conditions, actual binding constraints and actual congestion results. This is in contrast to the typical merger filing that uses predefined local markets based on historical conditions that no longer exist rather than the actual local markets based on current and potential market conditions. The MMU files comments with FERC including such analyses.[149] The MMU has proposed that FERC adopt this approach when evaluating mergers in PJM.[150] FERC has considered the MMU's analysis in reviewing mergers but continues to apply a definition of markets based on an outdated and static definition of relevant markets in PJM.[151]

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.[152] 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 3-92 shows ownership changes in the PJM market that involved entire resources that were completed in 2024, as reported to the Commission. Table 3-93 shows transactions that involved transfers of partial unit ownership that were completed in 2024, as reported to the Commission.[153]

141 See 175 FERC ¶ 61,231 (2021).
142 See 174 FERC ¶ 61,212 (2021).
143 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).
144 18 U.S.C. § 824b.
145 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)
146 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).
147 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.
148 See 138 FERC ¶ 61,109 (2012).
149 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).
150 See Comments of the Independent Market Monitor for PJM, Docket No. RM16-21 (Dec. 12, 2016).
151 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).
152 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.
153 The transaction completion date is based on the notices of consummation submitted to the Commission.

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Table 3-92 Completed transfers of entire resources: 2024

Generator or Generation Owner Name	From	To	Transaction Completion Date	Docket
Pittsburgh Airport Generating Facility	Peoples Natural Gas Company LLC	Cordia Holdings, LLC	January 30, 2024	EC24-10
Foxhound Solar, LLC	Longroad Energy Holdings, LLC	Dominion Energy, Inc	February 5, 2024	EC23-67
Richland-Stryker Generation LLC	Vistra Corp.	Rockland Capital, LP	March 4, 2024	EC24-35
Energy Harbor Nuclear Generation LLC (Beaver Valley, Davis Besse, Perry Nuclear Power Stations)	Energy Harbor Corp.	Vistra Corp.	March 1, 2024	EC23-74
Cambria Wind, LLC	Oppidum Green Energy USA, LLC	Partners Group Holding AG	March 21, 2024	EC24-39
Horus West Virginia 1, LLC	Opdenergy Holding, S.A.	Antin Infrastructure Partners S.A.S	March 26, 2024	EC23-107
Nestlewood Solar I, LLC	Vesper Energy Development LLC	Octopus Energy Group Limited	June 7, 2024	EC24-38
Kestrel Acquisition, LLC (Hunterstown Power Plant)	Platinum Equity, LLC	LS Power Development, LLC	July 16, 2024	EC24-42
Clean Energy Future - Lordstown, LLC	Macquarie Infrastructure Partners	Arclight Capital Partners, LLC	August 30, 2024	EC24-57
UGI Development Company (Hunlock Energy, LLC)	UGI Energy Services, LLC	Castelton Commodities International, LLC	September 30, 2024	EC24-98
Lanyard Power, LLC (Dickerson Power, LLC and Chalk Point Power, LLC	Olympus Power, LLC	Rockland Capital, LP	October 17, 2024	EC24-79
Bluegrass Solar, Ripley Solar, MD Solar, and Ben Moreell Solar	Vitol Inc.	MN8 Energy, LLC	December 13, 2024	EC24-113
Big Sky Wind, LLC	Vitol Inc	Power Corporation of Canada	December 30, 2024	EC24-121

Table 3-93 Completed transfers of partial ownership of resources: 2024

Generator or Generation Owner Name	Percent	From	To	Transaction Completion Date	Docket
Blue Harvest Solar Park LLC and Timber Road Solar Park LLC	80.0%	EDP Renewables North America LLC	Eni S.p.A	February 14, 2024	EC24-31
Homer City Holding LLC	20.0%	TCW Group, Inc	Knitghthead Capital Management, LLC	August 14, 2024	EC24-94
ECP ControlCo, LLC (Calpine Corporation, Convergent Energy and Power, Pivot Energy Holdings)	19.9%	ECP ControlCo, LLC	Bridgepoint, OP LLC	August 20, 2024	EC24-69
CPV Renewable Power LLC (Backbone Solar, Maple Hill Solar, Saddleback Ridge Wind, Stagecoach Solar)	33.3%	OPC Power Ventures LP	HS Renewable Co-Investment I, L.P.	November 13, 2024	EC24-115

Aggregate Market Pivotal Supplier Results

Notwithstanding the HHI level, a supplier may have the ability to raise energy market prices. If reliably meeting the PJM system load requires energy from a single supplier, that supplier is singly pivotal and has monopoly power in the aggregate energy market. If a small number of suppliers are jointly required to meet load, those suppliers are jointly pivotal and have oligopoly power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power. The identification of jointly pivotal suppliers as a source of market power does not require an assumption that the suppliers collude. There are multiple mechanisms that would permit the exercise of market power when there are limited suppliers providing relief to a constraint. FERC Order No. 697 also recognizes this explicitly in the discussion of HHI and pivotal suppliers.[154] 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 always correct, as demonstrated by these results. There are pivotal suppliers in the aggregate energy market.

The existing market power mitigation measures do not address aggregate market power.[155] Aggregate market power should be mitigated in the PJM Day-Ahead and Real-Time Markets when the three pivotal supplier test is failed.

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

155 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.

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Day-Ahead Energy Market Aggregate Pivotal Suppliers

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

Figure 3-57 shows the number of days in 2024 with one aggregate pivotal supplier, two aggregate jointly pivotal suppliers, and three aggregate jointly pivotal suppliers in the day-ahead energy market by peak load level. It shows that the frequency of pivotal suppliers increases with load. The average number of suppliers that were one of three pivotal suppliers (yellow line) was 0.7 on the 34 days with a peak load less than 90 GW (gray bar) and was 39.7 suppliers on the 39 days with a peak load between 120 and 130 GW. The number of pivotal suppliers increases with load. The two days with singly pivotal suppliers (teal line) were January 15 and July 15, 2024.

Figure 3-57 Average number of pivotal suppliers in the day-ahead energy market by load level

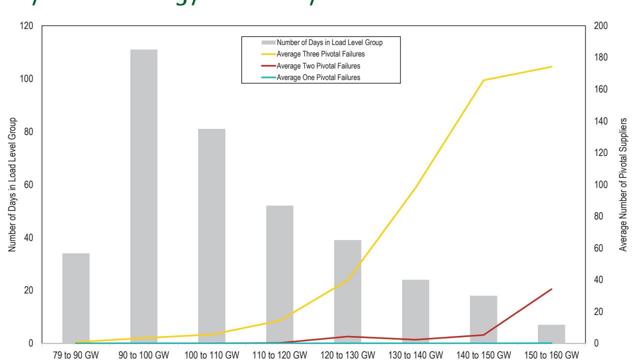

Table 3-94 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the day-ahead energy market in 2024. All of the top 10 suppliers were one of three pivotal suppliers on at least 79 days in 2024 (21.6 percent of the days).

Table 3-94 Day-ahead market pivotal supplier frequency: 2024

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	2	0.5%	49	13.4%	175	47.8%
2	1	0.3%	43	11.7%	166	45.4%
3	0	0.0%	44	12.0%	177	48.4%
4	0	0.0%	38	10.4%	145	39.6%
5	0	0.0%	34	9.3%	169	46.2%
6	0	0.0%	19	5.2%	90	24.6%
7	0	0.0%	10	2.7%	87	23.8%
8	0	0.0%	8	2.2%	113	30.9%
9	0	0.0%	5	1.4%	81	22.1%
10	0	0.0%	5	1.4%	79	21.6%

Market Behavior

Local Market Power

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

The three pivotal supplier (TPS) test is the test for local market power in the energy market.[156] If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners who have been identified as having local market power. Offer capping is designed to set offers at competitive levels. Competitive offers are defined to be cost-based energy offers. In the PJM energy market, units are required to submit cost-based energy offers, defined by fuel cost policies, and have the option to submit market-based, also called price-based, offers. Units are committed and dispatched on price-based offers, if offered, as the default offer.

156 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>.

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When a unit that submits both cost-based and price-based offers is mitigated to its cost-based offer by PJM, it is considered offer capped. A unit that submits only cost-based offers, or that requests PJM to dispatch it on its cost-based offer, is not considered offer capped.

Local market power mitigation is implemented in both the day-ahead and real-time energy markets. However, the implementation of the TPS test and offer capping differ in the day-ahead and real-time energy markets.

TPS Test Statistics for Local Market Power

The TPS test in the energy market defines whether 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 2024, in the day-ahead energy market, the 500 kV system, 20 zones, and PJM/MISO experienced congestion resulting from one or more constraints binding for 100 or more hours, or resulting from a binding interface constraint (Table 3-95).[157] Table 3-95 shows that the 500 kV system, 13 zones and PJM/MISO experienced congestion resulting from one or more constraints binding for 100 or more hours or resulting from a binding interface constraint in every year from 2015 through 2024. Two zones did not experience congestion resulting from one or more constraints binding for 100 or more hours or resulting from any binding interface constraint in any year from 2015 through 2024.[158]

Table 3-95 Day-ahead congestion hours resulting from one or more constraints binding for 100 or more hours: 2015 through 2024

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
500 kV System	8,797	7,350	7,937	4,360	7,507	5,248	2,662	2,983	1,225	1,772
ACEC	3,746	5,955	2,203	4,009	6,039	2,467	961	778	1,187	850
AEP	29,772	57,482	54,076	16,367	14,436	10,988	4,797	6,032	6,833	7,035
APS	5,104	11,445	11,513	3,884	3,129	3,592	3,094	1,904	2,243	2,262
ATSI	3,445	4,264	4,305	3,453	1,631	105	0	341	689	1,689
BGE	9,199	15,664	8,589	5,087	3,819	6,154	3,401	1,276	4,427	2,021
COMED	20,165	49,911	59,455	11,334	5,154	3,574	2,409	3,366	4,676	8,728
DAY	437	825	382	129	193	988	358	0	208	0
DEOK	8,478	9,577	8,112	2,598	1,444	218	348	620	318	246
DLCO	1,025	590	106	208	0	150	0	101	221	165
DOM	6,549	4,920	9,927	2,592	1,103	3,338	1,955	4,188	3,396	4,249
DPL	11,112	14,930	13,059	12,949	8,303	6,000	4,054	3,994	5,069	6,017
DUKE	0	0	0	0	0	0	0	0	0	0
DUQ	0	0	0	0	0	0	0	0	0	0
EKPC	215	3,833	1,313	521	0	0	0	0	163	104
EXT	1,360	0	440	177	0	0	0	0	0	0
JCPLC	3,883	4,179	2,089	1,521	317	1,706	0	814	2,238	1,746
MEC	2,148	5,586	6,111	4,337	3,958	2,092	2,138	3,018	2,312	3,416
NYISO	0	0	515	0	0	0	0	0	0	0
OVEC	0	0	0	0	1,853	2,560	0	1,021	1,737	630
PE	6,368	10,476	22,930	8,837	3,855	3,947	1,833	4,302	4,983	9,795
PECO	3,627	6,131	10,065	3,378	1,892	1,045	2,331	4,811	6,616	4,094
PEPCO	896	410	660	126	0	0	0	304	283	265
PJM/MISO	25,773	22,497	28,097	17,855	9,774	5,916	7,096	10,569	6,019	6,967
PPL	336	3,378	8,182	5,265	8,953	5,291	4,454	6,049	2,972	3,499
PSEG	16,458	16,816	21,390	6,696	2,733	2,446	3,544	5,125	2,288	1,137
REC	0	0	0	511	1,075	335	1,249	1,126	1,105	287
TVA	0	223	0	0	206	0	0	0	0	0

157 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.

158 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.

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In 2024, in the real-time energy market, the 500 kV system, 10 zones, and PJM/MISO experienced congestion resulting from one or more constraints binding for 100 or more hours, or resulting from a binding interface constraint (Table 3-96).[159] Table 3-96 shows that the 500 kV system, six zones, and PJM/MISO experienced congestion resulting from one or more constraints binding for 100 or more hours or resulting from a binding interface constraint in every year from 2015 through 2024. Six zones (Duke, DUQ, JCPLC, OVEC, PEPCO and REC) did not experience congestion resulting from one or more constraints binding for 100 or more hours or resulting from any binding interface constraint in any year from 2015 through 2024.[160]

Table 3-96 Real-time congestion hours resulting from one or more constraints binding for 100 or more hours: 2015 through 2024

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
500 kV System	665	804	944	1,112	4,470	2,217	1,060	1,021	375	782
ACEC	197	439	0	500	108	0	0	0	0	0
AEP	1,385	400	469	1,301	535	1,133	1,271	500	1,276	1,151
APS	167	0	265	246	191	322	1,474	0	313	182
ATSI	117	0	164	932	0	0	150	237	100	1,256
BGE	4,262	5,501	1,506	2,496	690	2,929	1,539	462	2,255	1,110
COMED	2,516	3,587	1,359	724	343	761	952	1,307	876	4,213
DAY	0	0	0	0	0	0	181	0	0	0
DEOK	112	0	0	0	0	0	0	139	0	0
DLCO	368	0	0	0	0	0	0	0	0	0
DOM	837	459	441	136	197	896	389	2,029	343	550
DPL	1,539	1,976	675	1,049	0	106	163	0	0	114
DUKE	0	0	0	0	0	0	0	0	0	0
DUQ	0	0	0	0	0	0	0	0	0	0
EKPC	0	0	0	200	0	0	0	0	0	0
EXT	0	0	788	0	0	0	0	0	0	0
JCPLC	0	0	0	0	0	0	0	0	0	0
MEC	111	0	116	755	465	1,042	412	1,232	502	590
NYISO	419	1,074	332	0	0	0	0	0	0	0
OVEC	0	0	0	0	0	0	0	0	0	0
PE	1,553	141	1,952	1,308	1,972	2,302	1,274	1,520	2,716	5,226
PECO	690	751	1,374	719	468	306	1,279	3,072	4,080	1,536
PEPCO	0	0	0	0	0	0	0	0	0	0
PJM/MISO	3,988	3,946	4,450	4,106	4,837	3,731	5,127	7,561	4,321	4,478
PPL	135	470	1,168	295	1,044	575	820	2,072	0	0
PSEG	1,698	407	240	113	0	0	898	296	0	0
REC	0	0	0	0	0	0	0	0	0	0

In the PJM Day-Ahead Energy Market, the TPS test is performed in PROBE, as part of the unit commitment process. Table 3-97 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.

159 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.

160 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.

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Table 3-97 Day-ahead three pivotal supplier test details for internal interface constraints: 2024

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	8	573	317	21	2	18
	Off Peak	47	401	618	25	10	15
AP South	Peak	119	671	1,129	32	13	18
	Off Peak	55	830	1,955	35	19	16
BCPEP	Peak	9	649	369	12	2	9
	Off Peak	1	201	387	12	0	12
Bedington - Black Oak	Peak	28	322	547	35	20	15
	Off Peak	117	353	892	33	22	11
Central	Peak	14	652	993	29	14	15
	Off Peak	0	0	0	0	0	0
East	Peak	5	314	788	21	5	16
	Off Peak	4	426	1,449	22	14	8
West	Peak	17	588	2,509	43	40	2
	Off Peak	8	663	1,494	27	8	19

Table 3-98 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market, 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.[161] 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 3-98 Day-ahead three pivotal supplier test details for top 10 congested constraints: 2024

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
East Towanda - Hillside	Peak	769	138	115	8	1	7
	Off Peak	717	130	176	8	0	8
Easton - Emuni	Peak	37	49	13	2	0	2
	Off Peak	6	26	5	1	0	1
Gardners - Texas Eastern	Peak	936	93	17	4	0	3
	Off Peak	474	91	15	4	0	4
Haumesser Road - Steward	Peak	561	250	235	11	1	10
	Off Peak	580	275	219	10	0	9
Kewanee	Peak	676	164	163	7	0	7
	Off Peak	849	170	143	6	0	6
Lenox - North Meshoppen	Peak	570	64	36	7	1	6
	Off Peak	779	56	41	8	1	8
Nottingham	Peak	1,413	183	429	31	23	8
	Off Peak	745	149	371	25	19	7
Prest - Tibb	Peak	18	55	32	4	0	4
	Off Peak	6	11	7	4	1	3
Sayreville - Sayreville	Peak	6	30	2	1	0	1
	Off Peak	14	20	3	1	0	1
East Lima - Haviland	Peak	430	115	141	15	2	13
	Off Peak	469	98	116	13	1	11

161 *See* PJM. "Manual 11: Energy & Ancillary Services Market Operations," Section 5.2.6, Rev. 133 (Dec. 17, 2024).

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The local market structure in the real-time energy market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results in 2024.[162] 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.[163] IT SCED solves for target times that occur at 15 minute time increments, unlike RT SCED that solves for every five minute time increment. The TPS statistics shown in this section present the data from the IT SCED TPS solution. Some IT SCED TPS solutions are used to commit units, while others are not. PJM operators have discretion in choosing which units to commit and which IT SCED results to use as the basis for the commitment and therefore which units are tested for market power using the TPS test. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Table 3-99 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 for the interface constraints in the PJM Real-Time Energy Market. Table 3-100 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the 10 constraints that were binding for the most hours in the PJM Real-Time Energy Market. Table 3-99 and Table 3-100 include analysis of all the tests for every target time where IT SCED determined that constraint relief was needed for each of the constraints shown. The same target time can be evaluated by multiple IT SCED cases at different look ahead times. Each 15 minute target time is solved by 12 different IT SCED cases at different look ahead times. The set of binding constraints for a target time may be different in 12 look ahead IT SCED solutions.

Table 3-99 Real-time three pivotal supplier test details for internal interface constraints: 2024

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AP South	Peak	1,871	390	622	13	2	11
	Off Peak	3,269	573	820	17	6	11
Bedington - Black Oak	Peak	1,754	126	164	12	3	9
	Off Peak	1,834	134	197	13	5	8
AEP - DOM	Peak	459	353	319	10	0	9
	Off Peak	1,242	466	403	9	1	8

162 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>.

163 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.

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Table 3-100 Real-time three pivotal supplier test details for top 10 congested constraints: 2024

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	58,156	22	26	3	0	2
	Off Peak	79,955	20	27	2	0	2
Kewanee	Peak	13,174	22	76	1	0	1
	Off Peak	12,410	21	70	1	0	1
Nottingham	Peak	38,670	117	148	12	3	9
	Off Peak	18,639	98	142	11	3	8
Prest - Tibb	Peak	6,773	22	10	3	0	3
	Off Peak	14,028	22	10	3	0	3
Haumesser Road - Steward	Peak	16,967	44	108	2	0	2
	Off Peak	15,859	40	93	2	0	2
East Towanda - Hillside	Peak	16,236	79	104	2	0	2
	Off Peak	19,777	69	122	2	0	2
Rising - Bondville	Peak	5,300	31	12	3	0	3
	Off Peak	10,040	31	15	3	0	3
Graceton - Safe Harbor	Peak	9,593	133	151	12	1	11
	Off Peak	9,449	98	125	11	2	9
Dune Acres - Michigan City	Peak	4,152	40	46	5	0	4
	Off Peak	10,035	39	49	5	0	4
Highland - Commerce	Peak	10,750	32	71	2	0	2
	Off Peak	6,848	17	48	2	0	2

The three pivotal supplier test is applied every time the IT SCED solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for offer capping. Steam unit offers that are offer capped in the day-ahead energy market continue to be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time. Steam unit offers that are not offer capped in the day-ahead energy market continue to not be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time.[164] 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 3-101 shows that, in 2024, 3.9 percent of unit hours that cleared the day-ahead market on their price based offer were switched to cost in real-time. Table 3-101 shows that 8.4 percent of unit hours that cleared the day-ahead market on their price based offer cleared on their price based offer in real-time despite failing the real-time TPS test.

Table 3-101 Day-ahead units committed on price-based offers that cleared real-time: 2023 and 2024

	Day Ahead Price Based Unit Hours That Cleared Real-Time			Percent Day Ahead Price Based Unit Hours That Cleared Real-Time	
Year	On Cost	On Price	On Price and Failed TPS Test	On Cost	On Price and Failed TPS Test
2023	85,417	2,502,803	278,944	3.0%	9.7%
2024	117,994	2,627,768	253,035	3.9%	8.4%

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 3-102 and Table 3-103 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

164 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.

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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 3-102 Summary of real-time three pivotal supplier tests applied for internal interface constraints: 2024

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
AP South	Peak	1,871	1,862	100%	40	2%	2%
	Off Peak	3,269	3,269	100%	61	2%	2%
Bedington - Black Oak	Peak	1,754	1,754	100%	19	1%	1%
	Off Peak	1,834	1,834	100%	61	3%	3%
AEP - DOM	Peak	459	459	0%	29	0%	0%
	Off Peak	1,242	1,242	100%	73	6%	6%

Table 3-103 Summary of real-time three pivotal supplier tests applied for top 10 congested constraints: 2024

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	58,156	28,453	49%	5	0%	0%
	Off Peak	79,955	20,817	26%	5	0%	0%
Kewanee	Peak	13,174	319	2%	0	0%	0%
	Off Peak	12,410	406	3%	0	0%	0%
Nottingham	Peak	38,670	38,580	100%	457	1%	1%
	Off Peak	18,639	18,573	100%	233	1%	1%
Prest - Tibb	Peak	6,773	627	9%	0	0%	0%
	Off Peak	14,028	1,105	8%	0	0%	0%
Haumesser Road - Steward	Peak	16,967	2,860	17%	0	0%	0%
	Off Peak	15,859	2,205	14%	0	0%	0%
East Towanda - Hillside	Peak	16,236	8,996	55%	0	0%	0%
	Off Peak	19,777	6,386	32%	0	0%	0%
Rising - Bondville	Peak	5,300	965	18%	0	0%	0%
	Off Peak	10,040	1,498	15%	2	0%	0%
Graceton - Safe Harbor	Peak	9,593	9,545	99%	91	1%	1%
	Off Peak	9,449	9,441	100%	91	1%	1%
Dune Acres - Michigan City	Peak	4,152	1,981	48%	0	0%	0%
	Off Peak	10,035	5,105	51%	0	0%	0%
Highland - Commerce	Peak	10,750	747	7%	0	0%	0%
	Off Peak	6,848	536	8%	0	0%	0%

Offer Capping for Local Market Power

In the PJM energy market, offer capping occurs as a result of structurally noncompetitive local markets and noncompetitive offers in the day-ahead and real-time energy markets. PJM also uses offer capping for units that are committed for reliability reasons, like voltage support and N-2 contingencies, for providing black start and for providing reactive service as well as for conservative operations. There are no explicit rules governing market structure or the exercise of market power in the aggregate energy market.

There are some issues with the application of mitigation in the day-ahead energy market and the real-time energy market when market sellers fail the TPS test. There are also issues with the absence of a TPS test under some conditions. There is no tariff or manual language that defines in detail the application of the TPS test and offer capping in the day-ahead energy market and the real-time energy market. There is no tariff or manual language that defines the PJM process for evaluating units for multi-day commitments in the day-ahead energy market.

In both the day-ahead and real-time energy markets, generators with market power have the ability to evade mitigation by using varying markups in their price-based offers, offering different operating parameters in their

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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.[165]

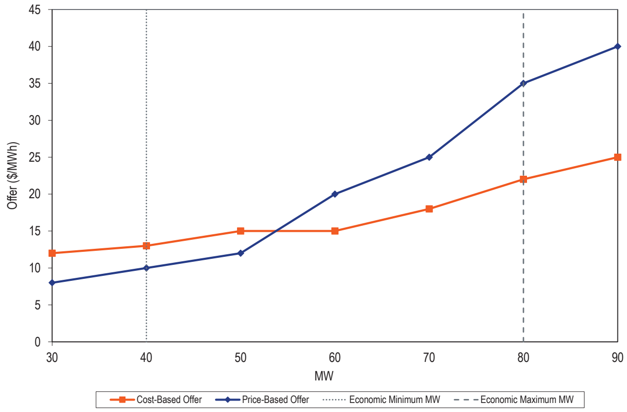
$$\text{Total Dispatch Cost} = \text{Startup Cost} + \sum_{\text{Min Run}} \text{Hourly Dispatch Cost}$$

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

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

The hourly dispatch cost is calculated only at the economic minimum level and not at higher output levels. Given the ability to submit offer curves with different markups at different output levels in the price-based offer, unit owners with market power can evade mitigation by using a low markup at low output levels and a high markup at higher output levels. This strategy is called crossing curves, or markup switching. Figure 3-58 shows an example of offers from a unit that has a negative markup at the economic minimum MW level and a positive markup at the economic maximum MW level. The result would be that a unit that failed the TPS test would be committed on its price-based offer that has a lower dispatch cost, even though the price-based offer is higher than cost-based offer at higher output levels and includes positive markups, inconsistent with the explicit goal of local market power mitigation.

Figure 3-58 Offers with varying markups at different MW output levels



165 See OA Schedule 1 § 6.4.1(g).

Table 3-104 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 2024. 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 3-104 Units offered with crossing curves (markup switch): 2024

	Day-Ahead			Real-Time		
2024	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	86,890	839,400	10.4%	73,782	775,515	9.5%
Feb	79,862	792,552	10.1%	63,141	736,063	8.6%
Mar	69,121	844,500	8.2%	53,785	696,611	7.6%
Apr	76,590	826,728	9.3%	61,495	677,110	9.1%
May	87,098	869,976	10.0%	72,655	736,427	9.9%
Jun	88,455	839,472	10.5%	83,877	786,417	10.7%
Jul	95,303	870,960	10.9%	90,379	821,874	11.0%
Aug	98,747	869,808	11.4%	90,266	823,331	11.0%
Sep	89,362	847,152	10.5%	76,991	763,796	10.1%
Oct	88,633	887,760	10.0%	62,853	693,099	9.1%
Nov	79,813	864,613	9.2%	59,349	710,932	8.3%
Dec	81,498	899,256	9.1%	69,946	812,552	8.6%
Total	1,021,372	10,252,177	10.0%	858,519	9,033,727	9.5%

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 3-105 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 3-105 Units offered with lower minimum run time on price compared to cost and with positive markup: 2024

	Day-Ahead			Real-Time		
2024	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	4,051	839,400	0.5%	3,649	775,515	0.5%
Feb	5,095	792,552	0.6%	4,470	736,063	0.6%
Mar	3,795	844,500	0.4%	3,035	725,824	0.4%
Apr	3,585	826,728	0.4%	2,730	677,110	0.4%
May	3,852	869,976	0.4%	3,114	736,427	0.4%
Jun	2,664	839,472	0.3%	1,657	786,417	0.2%
Jul	2,688	870,960	0.3%	1,749	821,874	0.2%
Aug	2,808	869,808	0.3%	1,777	823,331	0.2%
Sep	2,664	847,152	0.3%	1,440	763,796	0.2%
Oct	3,384	887,760	0.4%	2,020	693,099	0.3%
Nov	3,716	864,613	0.4%	2,462	710,932	0.3%
Dec	2,921	899,256	0.3%	2,073	812,552	0.3%
Total	41,223	10,252,177	0.4%	30,176	9,062,940	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 3-59 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

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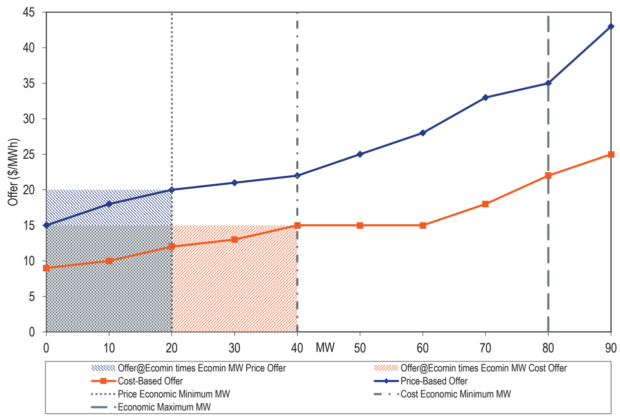
MW. However, the price-based offer includes a positive markup and could result in setting the market price at a noncompetitive level even after the resource owner fails the TPS test.

Figure 3-59 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 3-60 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 3-106 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 2024.

Figure 3-60 Dual fuel unit offers

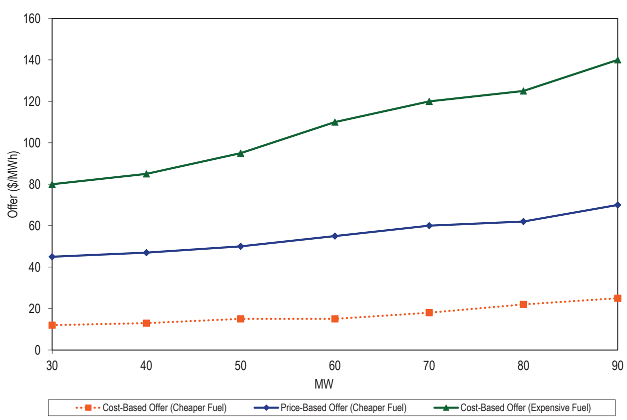


Table 3-106 Dual fuel unit offers with cost-based offers exceeding price-based offers (negative markup) but different fuel: 2024

	Day-Ahead			Real-Time		
2024	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	9,601	184,152	5.2%	9,601	181,606	5.3%
Feb	7,583	172,968	4.4%	7,583	168,544	4.5%
Mar	8,682	184,331	4.7%	8,682	156,824	5.5%
Apr	16,313	183,000	8.9%	16,313	157,157	10.4%
May	15,955	204,792	7.8%	15,955	184,139	8.7%
Jun	14,085	201,744	7.0%	14,085	198,272	7.1%
Jul	13,581	211,224	6.4%	13,581	206,114	6.6%
Aug	13,761	209,064	6.6%	13,761	201,932	6.8%
Sep	15,311	198,432	7.7%	15,311	187,967	8.1%
Oct	13,856	204,552	6.8%	13,856	158,729	8.7%
Nov	11,825	201,191	5.9%	11,825	163,310	7.2%
Dec	7,706	212,568	3.6%	7,706	202,760	3.8%
Total	148,259	2,368,018	6.3%	148,259	2,167,354	6.8%

These issues can be solved by simple rule changes.[166] 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.[167]

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.

166 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.

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

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.[168]

Levels of offer capping have historically been low in PJM, as shown in Table 3-108. But offer capping remains a critical element of PJM market rules because it is designed to prevent the exercise of local market power. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation. Until November 1, 2017, only uncommitted resources, started to relieve a transmission constraint, were subject to offer capping. Beginning November 1, 2017, under certain circumstances, online resources that are committed beyond their original commitment (day-ahead or real-time) can be offer capped if the owner fails the TPS test, and the latest available cost-based offer is determined to be lower than the price-based offer.[169] Units running in real time as part of their original commitment on the price-based

168 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>.

169 See OA Schedule 1 § 6.4.1.

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offer on economics, and that can provide incremental relief to a constraint, cannot be switched to their cost-based offer.

The offer capping percentages shown in Table 3-107 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.[170] 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 3-107 Offer capping statistics – energy only: 2018 to 2024

	Real-Time		Day-Ahead	
Year	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2018	0.9%	0.5%	0.1%	0.1%
2019	1.7%	1.3%	1.3%	0.9%
2020	1.0%	1.1%	1.6%	1.3%
2021	1.6%	1.3%	1.6%	1.0%
2022	1.4%	1.2%	1.2%	1.4%
2023	1.3%	1.0%	1.7%	0.8%
2024	1.5%	1.1%	1.2%	0.9%

Table 3-108 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 3-109. 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 3-107. 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 3-109.

Table 3-108 Offer capping statistics for energy and reliability: 2018 to 2024

	Real-Time		Day-Ahead	
Year	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2018	1.0%	0.8%	0.2%	0.3%
2019	1.7%	1.3%	1.3%	0.9%
2020	1.0%	1.1%	1.6%	1.3%
2021	1.6%	1.3%	1.6%	1.0%
2022	1.4%	1.3%	1.7%	1.4%
2023	1.4%	1.2%	1.8%	1.0%
2024	1.5%	1.3%	2.1%	1.3%

Table 3-109 shows the offer capping percentages only for units committed for reliability reasons, black start or reactive support. The low offer capping percentages do not mean that units manually committed for reliability reasons do not have market power. All units manually committed for reliability have market power, and all are treated as if they had market power.

Table 3-109 Offer capping statistics for reliability: 2018 to 2024

	Real-Time		Day-Ahead	
Year	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2018	0.13%	0.29%	0.10%	0.21%
2019	0.01%	0.02%	0.00%	0.01%
2020	0.00%	0.01%	0.00%	0.00%
2021	0.03%	0.04%	0.02%	0.03%
2022	0.05%	0.09%	0.04%	0.05%
2023	0.14%	0.23%	0.13%	0.23%
2024	0.08%	0.15%	0.21%	0.37%

Table 3-110 presents data on the frequency with which units were offer capped in 2023 and 2024 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 3-110 shows that six units were offer capped for 90 percent or more of their run hours in 2024, compared to four units with 90 percent or more offer capped run hours in 2023.

170 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.

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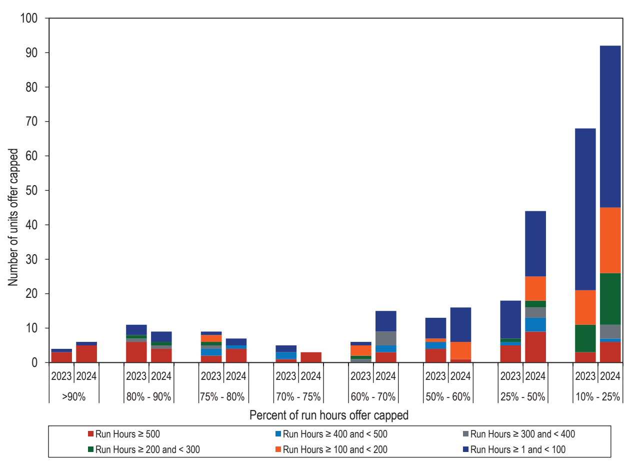
Table 3-110 Real-time offer capped unit statistics: 2023 and 2024

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:		Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2023	3	0	0	0	0	1
	2024	5	0	0	0	0	1
80% and < 90%	2023	6	0	1	1	0	3
	2024	4	0	1	1	0	3
75% and < 80%	2023	2	2	1	1	2	1
	2024	4	1	0	0	0	2
70% and < 75%	2023	1	2	0	0	0	2
	2024	3	0	0	0	0	0
60% and < 70%	2023	0	0	1	1	3	1
	2024	3	2	4	0	0	6
50% and < 60%	2023	4	2	0	0	1	6
	2024	1	0	0	0	5	10
25% and < 50%	2023	5	1	0	1	0	11
	2024	9	4	3	2	7	19
10% and < 25%	2023	3	0	0	8	10	47
	2024	6	1	4	15	19	47

Figure 3-61 shows the frequency with which units were offer capped in 2023 and 2024 for failing the TPS test to provide energy for constraint relief in the real-time energy market or for reliability reasons.

Figure 3-61 Real-time offer capped unit statistics: 2023 and 2024



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.[171] [172] PJM also reported that between 2019 and 2022, the percent of unit intervals in the real-time energy market with active market power mitigation was between 43.3 and 53.3 percent, while the actual results were between 1.0 and 1.7 percent. PJM's reported results were incorrect because PJM provided hours of mitigation instead of unit hours or unit intervals mitigated. In the day-ahead market, a mitigated unit hour is one unit mitigated for one hour. The denominator is all cleared units cleared for all hours. In the real-time market, a mitigated unit interval is one unit mitigated for one interval. The denominator is all cleared units for all intervals. For example, if there were 10 units running in a given hour in the day-ahead market, if one unit was mitigated for that hour, then the percent of unit hours mitigated would be 10 percent, but PJM defined the percent mitigated as 100 percent of the hour. The PJM filed report dramatically overstated the frequency of market power mitigation in the PJM energy market. The MMU has correctly reported this metric in the State of the Market Reports for 2002 and subsequent years. The MMU also reports the MWh subject to market power mitigation, which reflects the relative size of the units subject to market power mitigation.

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.[173] 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.

171 See Common Performance Metrics, Docket No. AD19-16-000, PJM Compliance Filing, PJM Metrics Spreadsheet 2023 (April 17, 2023).

172 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>.

173 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.

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Real-Time Markup Index

Table 3-111 shows the average markup index of marginal units in the real-time energy market, by offer price category using unadjusted cost-based offers.

Table 3-112 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.[174] 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.[175]

In 2024, the average dollar markup of units with offer prices less than $10 was negative (-$1.67 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $10 and $15 was negative (-$1.90 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 2024, 1.4 percent had offer prices above $150 per MWh. Among the units that were marginal in 2023, 1.5 percent had offer prices greater than $150 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in 2024 was more than $900, and the highest markup in 2023 was more than $400.

Table 3-111 Real-time average marginal unit markup index (By offer price category unadjusted): 2023 and 2024

	2023			2024		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	(0.15)	($2.21)	17.3%	(0.14)	($1.67)	28.8%
$10 to $15	(0.07)	($1.38)	15.3%	(0.11)	($1.90)	15.7%
$15 to $20	(0.05)	($1.24)	20.4%	(0.10)	($2.71)	16.6%
$20 to $25	(0.02)	($1.27)	15.9%	(0.06)	($2.77)	12.6%
$25 to $50	0.02	($0.28)	25.9%	0.02	($1.48)	20.3%
$50 to $75	0.18	$9.94	2.7%	0.13	$6.31	3.3%
$75 to $100	0.26	$21.17	0.6%	0.21	$15.33	0.8%
$100 to $125	0.48	$52.71	0.2%	0.32	$33.98	0.4%
$125 to $150	0.33	$43.81	0.1%	0.26	$36.03	0.2%
>= $150	0.07	$14.03	1.5%	0.11	$22.43	1.4%
All Offers	(0.03)	($0.35)	100.0%	(0.06)	($1.04)	100.0%

174 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.

175 See PJM. "Manual 15: Cost Development Guidelines," Rev. 45 (Sep. 1, 2023).

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Table 3-113 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.[176]

Table 3-112 Real-time average marginal unit markup index (By offer price category adjusted): 2023 and 2024

	2023			2024		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	(0.11)	($1.77)	17.3%	(0.11)	($1.26)	28.8%
$10 to $15	(0.01)	($0.35)	15.3%	(0.03)	($0.81)	15.7%
$15 to $20	0.02	$0.07	20.4%	(0.03)	($1.33)	16.6%
$20 to $25	0.04	$0.32	15.9%	0.00	($1.07)	12.6%
$25 to $50	0.08	$2.05	25.9%	0.08	$0.90	20.3%
$50 to $75	0.24	$13.17	2.7%	0.18	$9.72	3.3%
$75 to $100	0.30	$24.89	0.6%	0.25	$19.54	0.8%
$100 to $125	0.50	$55.60	0.2%	0.35	$37.17	0.4%
$125 to $150	0.37	$48.54	0.1%	0.29	$39.89	0.2%
>= $150	0.13	$32.87	1.5%	0.16	$36.77	1.4%
All Offers	0.03	$1.41	100.0%	(0.01)	$0.54	100.0%

Table 3-114 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 2024, using unadjusted cost-based offers for coal units, 57.7 percent of marginal coal units had negative markups. The share of marginal gas units with negative markups at the dispatch point on their offer curve increased from 51.2 percent in 2023 to 64.2 percent in 2024 when using unadjusted cost based offers.

Table 3-113 Percent of marginal units with markup below, above and equal to zero (By fuel type with unadjusted offers): 2023 and 2024

	2023			2024		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	49.98%	30.14%	19.89%	57.69%	28.55%	13.77%
Gas	51.26%	14.49%	34.25%	64.20%	15.83%	19.98%
Oil	3.05%	96.83%	0.12%	11.55%	82.31%	6.15%

In 2024, using adjusted cost-based offers for coal units, 48.1 percent of marginal coal units had negative markups.

Table 3-114 Percent of marginal units with markup below, above and equal to zero (By fuel type with adjusted offers): 2023 and 2024

	2023			2024		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	36.99%	6.54%	56.46%	48.11%	8.03%	43.87%
Gas	36.46%	9.56%	53.98%	43.83%	9.23%	46.94%
Oil	1.92%	96.83%	1.24%	10.90%	81.56%	7.54%

Figure 3-62 shows the frequency distribution of hourly markups for all gas units offered in 2023 and 2024 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.[177] Of the gas units offered in the PJM market in 2024, 20.9 percent of gas unit hours had a maximum markup that was negative and 21.2 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 2024 compared to 2023, while the share of marginal gas units with negative markups at the dispatch point increased.

Figure 3-62 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: 2023 and 2024

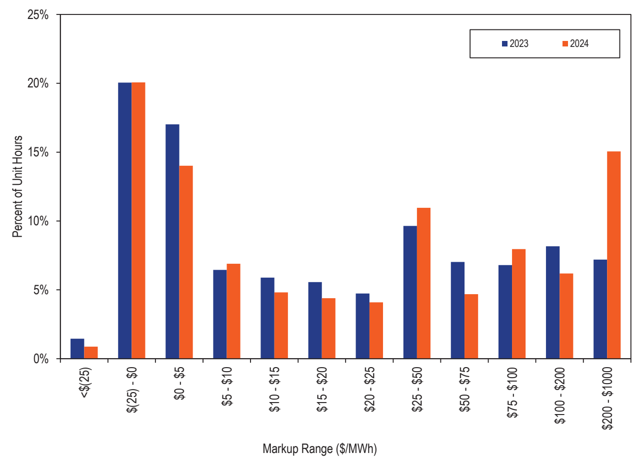

Figure 3-63 shows the frequency distribution of hourly markups for all coal units offered in 2023 and 2024 using unadjusted cost-based offers. Of the coal units offered in the PJM market in 2023, 33.1 percent of coal unit hours had a maximum markup that was negative or equal to zero, decreasing from 35.3 percent in 2023. The share of offered coal units with maximum markup that was negative decreased in 2024, while the share of marginal coal units with negative markups at the dispatch point increased in 2024 compared to 2023.

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

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

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Figure 3-63 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: 2023 and 2024

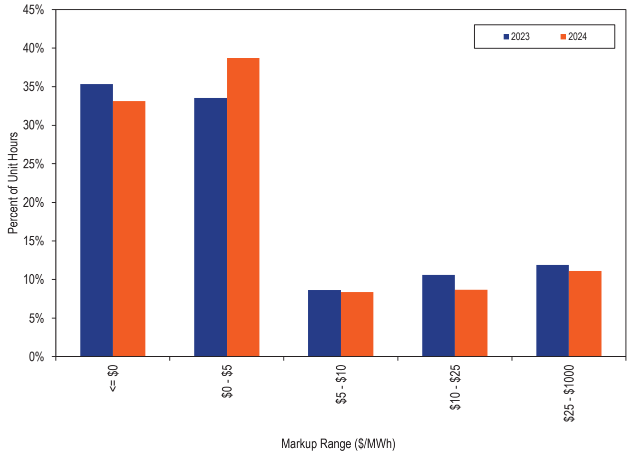
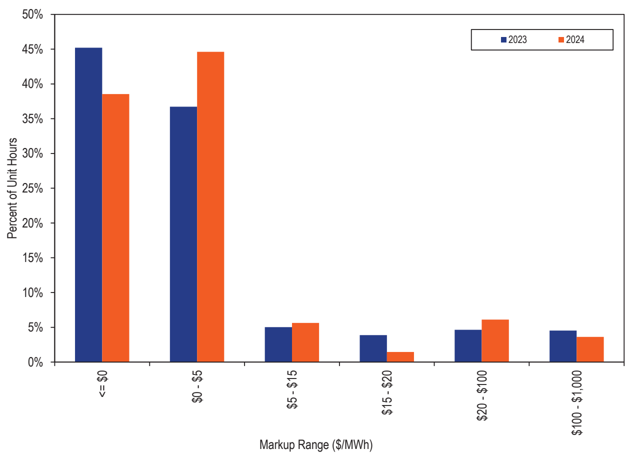


Figure 3-64 shows the frequency distribution of hourly markups for all offered oil units in 2023 and 2024 using unadjusted cost-based offers. Of the oil units offered in the PJM market in 2024, 38.5 percent of oil unit hours had a maximum markup that was negative or equal to zero. More than 3.6 percent of oil fired unit hours had a maximum markup above $100 per MWh.

Figure 3-64 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: 2023 and 2024

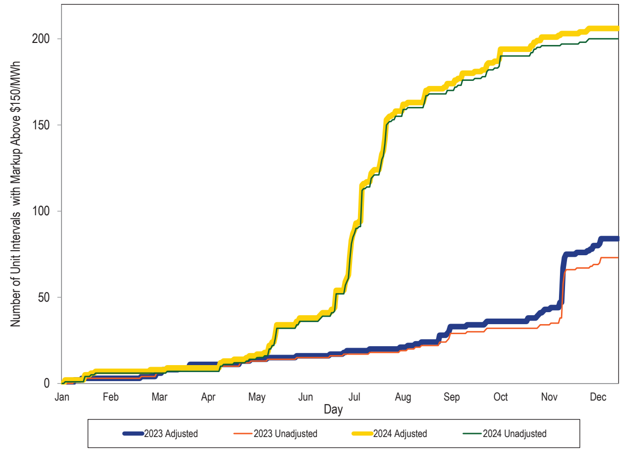


The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion 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 3-65 shows the number of marginal unit intervals in 2024 and 2023 with markup above $150 per MWh.

Figure 3-65 Cumulative number of unit intervals with markups above $150 per MWh: 2023 through 2024



Day-Ahead Markup Index

Table 3-115 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using unadjusted cost-based offers.

The majority of marginal units in the day-ahead market are virtual transactions, which do not have markup. The average dollar markups of units with offer prices less than $10 was $9.52 per MWh when using unadjusted cost-based offers in 2024.

Some marginal units did have substantial markups. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the day-ahead market in 2024 was more than $200 per MWh and the highest markup in 2023 was more than $250 per MWh.

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Table 3-115 Average day-ahead marginal unit markup index (By offer price category, unadjusted): 2023 and 2024

	2023			2024		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.08	($0.84)	16.6%	(0.53)	$9.52	20.0%
$10 to $15	0.09	$0.82	16.9%	0.43	$4.80	20.9%
$15 to $20	0.17	$2.72	31.1%	0.13	$1.72	31.8%
$20 to $25	0.11	$1.26	39.9%	0.08	$1.49	36.2%
$25 to $50	0.06	$1.47	73.6%	0.10	$3.08	71.2%
$50 to $75	0.08	$3.31	42.8%	0.09	$4.17	44.8%
$75 to $100	0.06	$5.71	8.3%	0.08	$3.42	15.8%
$100 to $125	0.18	$19.29	3.3%	0.13	$14.40	7.7%
$125 to $150	0.00	$0.00	1.2%	0.14	$17.62	3.2%
>= $150	0.04	$9.62	6.9%	0.03	$6.75	7.0%
All Offers	0.09	$1.70	100.0%	0.08	$3.83	100.0%

Table 3-116 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using adjusted cost-based offers.

In 2024, 71.2 percent of day-ahead marginal generation units had offers between $25 and $50 per MWh. For units that have an offer price less than $10, the average markup index decreased from 0.17 in 2023 to -0.52 in 2024.

Table 3-116 Average day-ahead marginal unit markup index (By offer price category, adjusted): 2023 and 2024

	2023			2024		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.17	($0.84)	16.6%	(0.52)	$9.52	20.0%
$10 to $15	0.15	$0.82	16.9%	0.50	$4.80	20.9%
$15 to $20	0.22	$2.72	31.1%	0.19	$1.72	31.8%
$20 to $25	0.16	$1.26	39.9%	0.14	$1.49	36.2%
$25 to $50	0.12	$1.47	73.6%	0.16	$3.08	71.2%
$50 to $75	0.13	$3.31	42.8%	0.15	$4.17	44.8%
$75 to $100	0.12	$5.71	8.3%	0.12	$3.42	15.8%
$100 to $125	0.27	$19.29	3.3%	0.18	$14.40	7.7%
$125 to $150	0.04	$0.00	1.2%	0.21	$17.62	3.2%
>= $150	0.11	$9.62	6.9%	0.12	$6.75	7.0%
All Offers	0.15	$1.70	100.0%	0.13	$3.83	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 3-117 shows the caps on the three parts of cost-based and price-based offers.

Table 3-117 Cost-based and price-based offer caps

Offer Type	No Load and Start Cost Option	Incremental Offer Curve Cap	No Load Cost Cap	Start Cost Cap
Cost-Based	Cost-Based	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies		
Price-Based	Cost-Based	$1,000/MWh or based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies if verified cost-based offer exceeds $1,000/MWh but no more than $2,000/MWh.	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies
	Price-Based		No cap but can only be changed twice a year.	No cap but can only be changed twice a year.

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Table 3-118 shows the number of units that chose the cost-based option and the price-based option. In 2024, 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, two percentage points higher than in 2023.

Table 3-118 Number of units selecting cost-based and price-based no load and start costs: 2023 and 2024

	2023		2024	
No Load and Start Cost Option	Number of units	Percent	Number of units	Percent
Cost-Based	472	88%	466	90%
Price-Based	62	12%	51	10%
Total	534	100%	517	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 3-119 shows the average markup in the no load and start costs in 2023 and 2024. 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 2024, 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 3-119 No load and start cost markup: 2023 and 2024

Period	No Load and Start Cost Option	No Load Cost	Cold Start Cost	Intermediate Start Cost	Hot Start Cost
2023	Cost-Based	(8%)	(6%)	(6%)	(7%)
	Price-Based	10%	197%	183%	186%
2024	Cost-Based	(14%)	(5%)	(6%)	(7%)
	Price-Based	25%	140%	125%	125%

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 2024, 7.8 percent of the marginal units set prices based on cost-based offers, 1.7 percentage points higher than in 2023.

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

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include a cost in an energy market cost-based offer, a variable cost, is that the cost is "directly related to electric production."[178]

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.[179]

Avoidable costs are annual costs that would be avoided if energy were not produced over an annual period. The PJM rules divide avoidable costs into those that are directly related to electric production and those not directly related to electric production. The distinction is ambiguous at best. PJM includes overhaul and maintenance costs, replacement of obsolete equipment, and overtime staffing costs in costs related to electric production. PJM includes taxes, preventative maintenance to auxiliary equipment, improvement of working equipment, maintenance expenses triggered by a time milestone (e.g. annual, weekly) and pipeline reservation charges in costs not related to electric production.

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

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

Fuel Cost Policies

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

Fuel Cost Policy Review

Table 3-120 shows the status of all fuel cost policies (FCP). As of December 31, 2024, 696 units (90 percent) had an FCP passed by the MMU and 73 units (10 percent) had an FCP failed by the MMU. The units with fuel cost policies failed by the MMU represented 18,891 MW. All units' FCPs were approved by PJM. As of December 31, 2024, 607 units did not have FCPs. Units without FCPs cannot submit nonzero cost based offers, unless they use the temporary cost method.[180]

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

Table 3-120 FCP Status for PJM generating units: December 31, 2024

	MMU Status			
PJM Status	Pass	Submitted	Fail	Total
Submitted	0	0	0	0
Under Review	0	0	0	0
Customer Input Required	0	0	0	0
Approved	696	0	73	769
Total	696	0	73	769

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

The standards for the MMU's market power evaluation are that FCPs be algorithmic, verifiable and systematic, accurately reflecting the short run marginal cost of producing energy. In its filings with FERC, PJM agreed with the MMU that FCPs should be verifiable and systematic.[181] 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.[182] 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.[183] 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').[184]

180 See OA Schedule 2 § 2.1.
181 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").
182 Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) at P 8 ("September 16th Filing").
183 October 7th Filing at P12; 158 FERC ¶ 61,133 at P 57 (2017).
184 September 16th Filing at P 8.

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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).[185]

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.

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

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.

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.[186] Penalties are assessed when both PJM and the MMU are in agreement.

In 2024, of the 77 penalty cases, 70 have been assessed cost-based offer penalties and seven remain pending. These cases were for 67 units owned by 21 different companies. Table 3-121 shows the penalties by the year in which participants were notified.

Table 3-121 Cost-based offer penalty cases by year notified: May 2017 through December 2024

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	70	38	0	7	67	21
Total	830	786	168	37	7	505	77

Since 2017, of the 830 penalty cases, 786 resulted in assessed cost-based offer penalties, 37 resulted in disagreement between the MMU and PJM, and seven remain pending. A total of 168 were self identified by market sellers. The 786 cases were from 505 units owned

186 See OA Schedule 2 § 6.

by 77 different companies. The total penalties were $5.8 million, charged to units that totaled 159,614 available MW. The average penalty was $1.60 per available MW. This means that a 100 MW unit would have paid a penalty of $3,846.[187] 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 3-122 shows the total cost-based offer penalties since 2017 by year.

Table 3-122 Cost-based offer penalties by year: May 2017 through December 2024

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	34	$1,242,102	25,743	$2.28
2019	73	23	$378,245	15,073	$1.14
2020	140	27	$407,283	21,908	$0.85
2021	125	25	$753,463	24,808	$1.31
2022	123	21	$1,613,621	24,385	$2.76
2023	61	16	$339,879	10,564	$1.33
2024	72	21	$499,897	20,203	$1.03
Total	813	72	$5,791,316	159,614	$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.

The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy.

Cost Development Guidelines

The Cost Development Guidelines contained in PJM Manual 15 do not clearly or accurately describe the short run marginal cost of generation. The MMU recommends that PJM Manual 15 be replaced or updated with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers 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.[188]

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.[189] 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.[190] On October 28, 2019, FERC issued a final order accepting PJM's compliance filing.[191] 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.

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.

187 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.

188 See PJM Manual 15: Cost Development Guidelines, Revision 45 (Sep. 1, 2024).

189 See PJM Interconnection Maintenance Adder Revisions to the Amended and Restated Operating Agreement, L.L.C., Docket No. EL19-8-000.

190 167 FERC ¶ 61,030 (2019).

191 168 FERC ¶ 61,134 (2019).

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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 3-123 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 3-123 Effective VOM costs in dollars per MWh: 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.[192]

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 3-124 shows the default adders for operating cost and minor maintenance.

Table 3-124 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

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

192 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>.

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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.[193]

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.[194]

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.

193 The peak adder is equal to $300 times three divided by 5 MW.
194 *See* Federal Energy Regulatory Commission, Docket No. ER23-557-000 (January 10, 2023) at 1.

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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.[195] 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.[196]

Even though the MMU developed and supported the new definition, it is important to recognize that this approach should be temporary until PJM implements an approach that reflects soak time, soak costs and soak energy output. The main shortcoming of the new definition is that PJM models do not properly value the energy produced during the soak process (soak energy output). Instead, the proposal simply assumes that such MWh are valued at PJM's station service rate. The ideal solution is to model start costs and soak costs separately since there are revenues associated with the MWh produced during soaking, while during the start process there are no MWh being injected into the grid.

The MMU recommends that soak costs, soak time and the MWh produced during soaking be modeled separately. This will ensure that the time required for units to reach a dispatchable level is known and used in the unit commitment process instead of only being communicated verbally between dispatchers and generators. Separating soak costs from start costs and modeling the MWh produced during soaking allows for a better representation of the costs because it eliminates the need to simply assume the price paid for those MWh.

Nuclear Costs

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

The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the PJM Manual 15.

195 *See* "Start Cost Alternate Proposal," MMU presentation to the Cost Development Subcommittee. (December 2, 2021) <20211202-item-06-start-cost-alternate-proposal.ashx>.

196 *See* Federal Energy Regulatory Commission, Docket No. ER23-557-000 (January 10, 2023) at 1.

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.[197] 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.

197 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).

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Table 3-125 shows, by month, the number of FMUs and AUs from January 2021 through December 2024. For example, in January 2021, there were zero units that qualified as an FMU or AU in Tier 1, one unit qualified as an FMU or AU in Tier 2, and zero units qualified as an FMU or AU in Tier 3.

Table 3-125 Number of frequently mitigated units and associated units (By month): January 2021 through December 2024

	2021				2022				2023				2024			
	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
February	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
April	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
June	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
August	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
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

For the 2020/2021 through 2022/2023 planning years, default Avoidable Cost Rates were not defined in the tariff. During this period, if a generating unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis (in $/MW-year) were greater than zero, and if the generating unit did not have an approved unit specific Avoidable Cost Rate, the generating unit would not qualify as an FMU as the Avoidable Cost Rate will be assumed to be zero for FMU qualification purposes.

The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

Market Performance

Ownership of Marginal Resources

Table 3-126 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.[198] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of 2024, and summed by the parent company that offers the marginal resource into the real-time energy market. In 2024, the offers of one company resulted in 16.4 percent of the real-time load-weighted PJM system LMP and the offers of the top four companies resulted in 43.4 percent of the real-time load-weighted average PJM system LMP. In 2024, the offers of one company resulted in 17.4 percent of the peak hour real-time load-weighted PJM system LMP.

Table 3-126 Marginal unit contribution to real-time load-weighted LMP (By parent company): 2023 and 2024

2023						2024					
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	15.5%	15.5%	1	15.7%	15.7%	1	16.4%	16.4%	1	17.4%	17.4%
2	8.9%	24.5%	2	9.9%	25.6%	2	9.9%	26.4%	2	11.9%	29.3%
3	8.3%	32.7%	3	8.8%	34.4%	3	9.6%	35.9%	3	8.2%	37.5%
4	8.1%	40.9%	4	7.2%	41.6%	4	7.4%	43.4%	4	7.5%	44.9%
5	7.3%	48.2%	5	7.1%	48.6%	5	5.8%	49.2%	5	4.8%	49.7%
6	6.9%	55.1%	6	6.4%	55.1%	6	4.0%	53.2%	6	4.5%	54.2%
7	3.7%	58.8%	7	3.3%	58.4%	7	4.0%	57.2%	7	3.7%	58.0%
8	2.8%	61.5%	8	3.0%	61.4%	8	3.8%	61.0%	8	3.5%	61.5%
9	2.6%	64.2%	9	2.6%	64.0%	9	3.1%	64.0%	9	2.9%	64.4%
Other (85 companies)	35.8%	100.0%	Other (82 companies)	36.0%	100.0%	Other (94 companies)	36.0%	100.0%	Other (92 companies)	35.6%	100.0%

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

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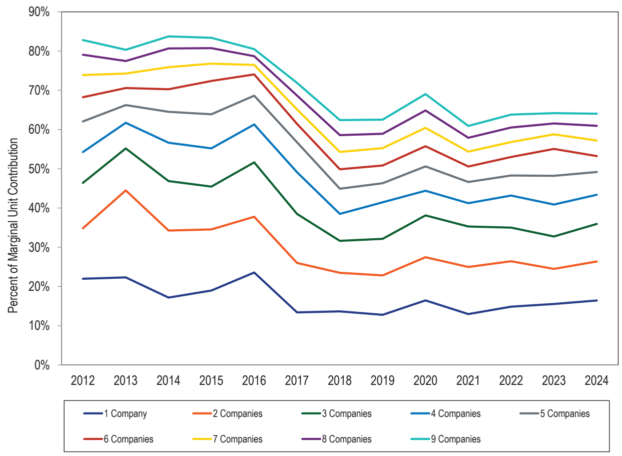
Figure 3-66 shows the marginal unit contribution to the real-time load-weighted PJM system LMP summed by parent companies for every year since 2012.

Figure 3-66 Marginal unit contribution to real-time load-weighted LMP (By parent company): 2012 through 2024



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

The markup calculation is not based on a counterfactual redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at short run marginal cost. A full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on short run marginal cost and actual dispatch. It is possible that the unit specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has short run marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

Real-Time Markup

Markup Component of Real-Time Price by Fuel, Unit Type

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units.

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.

199 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.

Table 3-127 shows the impact (markup component of LMP) of the marginal unit markup behavior by fuel type and unit type on the real-time load-weighted average system LMP using unadjusted and adjusted offers. The adjusted markup component of LMP decreased from $2.67 per MWh in 2023 to $1.98 per MWh in 2024. The adjusted markup contribution of coal units in 2024 was $0.26 per MWh, an increase of $0.16 per MWh from 2023. The adjusted markup component of gas fired units in 2024 was $2.18 per MWh, a decrease of $0.51 per MWh from 2023. The markup component of wind units was $0.02 per MWh. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In 2024, among the wind units that were marginal, 58.5 percent had negative offer prices.

Table 3-127 Markup component of real-time load-weighted average LMP by primary fuel type and unit type: 2023 and 2024[200]

		2023		2024	
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($0.40)	$0.10	($0.21)	$0.26
Gas	CC	$1.03	$1.91	$0.72	$1.60
Gas	CT	$0.36	$0.80	$0.12	$0.56
Gas	RICE	($0.01)	$0.01	($0.01)	$0.01
Gas	Steam	($0.10)	($0.03)	($0.06)	$0.01
Municipal Waste	RICE	$0.02	$0.02	$0.02	$0.02
Oil	CC	($0.03)	($0.02)	($0.00)	($0.00)
Oil	CT	($0.10)	($0.09)	($0.55)	($0.46)
Oil	RICE	$0.00	$0.00	($0.00)	$0.00
Oil	Steam	($0.07)	($0.06)	($0.14)	($0.12)
Other	Battery	$0.00	$0.00	$0.00	$0.00
Other	Solar	$0.01	$0.01	$0.07	$0.07
Other		$0.00	$0.00	$0.01	$0.01
Wind		$0.01	$0.01	$0.02	$0.02
Total		$0.73	$2.67	($0.01)	$1.98

Markup Component of Real-Time Price

Table 3-128 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-129 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on peak and off peak prices. In 2024, when using unadjusted cost-based offers, -$0.01 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-based offers, $1.98 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In 2024, the peak markup component was highest in July, $6.10 per MWh using unadjusted cost-based offers and $8.87 per MWh using adjusted cost-based offers. This corresponds to 10.0 percent and 14.6 percent of the real-time peak load weighted average LMP in July.

Table 3-128 Monthly markup components of real-time load-weighted LMP (Unadjusted): 2023 through 2024

	2023			2024		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$0.45	$0.45	$0.44	($3.81)	($2.55)	($5.05)
Feb	($0.82)	($0.39)	($1.25)	$0.12	$0.60	($0.36)
Mar	$0.51	$0.66	$0.34	($0.14)	($0.68)	$0.34
Apr	$0.08	$0.50	($0.31)	$1.49	$2.00	$0.92
May	$0.69	$1.41	($0.07)	($0.57)	($0.17)	($1.00)
Jun	$1.08	$1.72	$0.33	($0.45)	($1.01)	$0.11
Jul	$1.82	$3.41	$0.31	$3.72	$6.10	$1.11
Aug	$2.09	$2.41	$1.72	$2.31	$4.47	($0.07)
Sep	$0.92	$1.08	$0.76	($0.33)	($0.28)	($0.37)
Oct	$1.37	$2.24	$0.43	($1.60)	($1.64)	($1.56)
Nov	$0.05	$0.36	($0.25)	($0.06)	$0.76	($0.81)
Dec	($0.02)	$0.32	($0.31)	($1.38)	($1.43)	($1.32)
Total	$0.73	$1.26	$0.20	($0.01)	$0.67	($0.70)

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

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Table 3-129 Monthly markup components of real-time load-weighted LMP (Adjusted): 2023 through 2024

	2023			2024		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$2.56	$2.70	$2.43	($0.78)	$0.62	($2.16)
Feb	$0.86	$1.42	$0.30	$1.77	$2.26	$1.28
Mar	$2.32	$2.56	$2.06	$1.29	$0.88	$1.66
Apr	$1.79	$2.45	$1.19	$3.03	$3.65	$2.35
May	$2.42	$3.35	$1.42	$1.38	$2.00	$0.72
Jun	$2.85	$3.69	$1.87	$1.50	$1.28	$1.72
Jul	$4.13	$6.12	$2.23	$6.03	$8.87	$2.91
Aug	$4.18	$4.72	$3.53	$4.15	$6.54	$1.51
Sep	$2.90	$3.37	$2.45	$1.48	$1.72	$1.25
Oct	$3.28	$4.33	$2.17	$0.24	$0.38	$0.08
Nov	$2.15	$2.61	$1.70	$1.79	$2.79	$0.88
Dec	$1.93	$2.45	$1.48	$0.98	$1.06	$0.90
Total	$2.67	$3.41	$1.93	$1.98	$2.86	$1.08

Hourly Markup Component of Real-Time Prices

Figure 3-67 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in 2024 and 2023. Figure 3-68 shows the markup contribution to the hourly load-weighted LMP using adjusted cost-based offers in 2024 and 2023.

Figure 3-67 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): January 2023 through December 2024

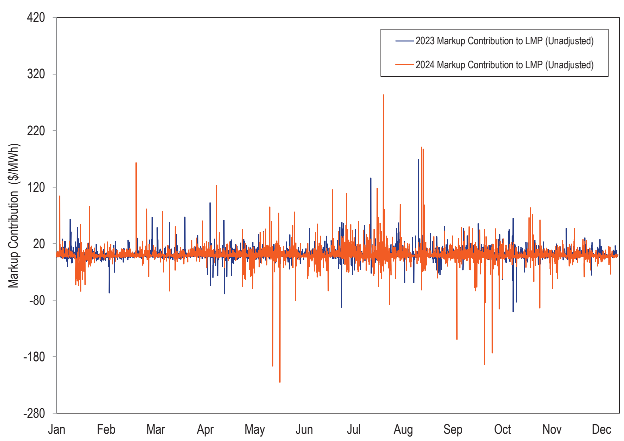
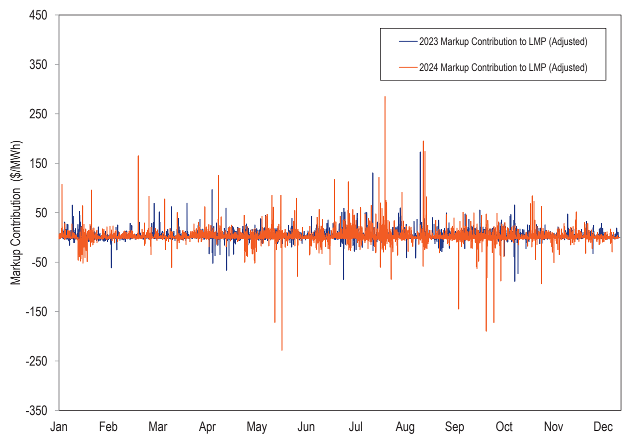


Figure 3-68 Markup contribution to real-time hourly load-weighted LMP (Adjusted): January 2023 through December 2024



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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 2023 and 2024 in Table 3-130 and for adjusted offers in Table 3-131.[201] The smallest zonal all hours average markup component using unadjusted offers in 2024, was in the PPL Zone, -$0.80 per MWh, while the highest was in the BGE Zone, $1.10 per MWh. The smallest zonal on peak average markup component using unadjusted offers in 2024, was in the PPL Zone, -$0.20 per MWh, while the highest was in the BGE Zone, $1.78 per MWh.

Table 3-130 Real-time average zonal markup component (Unadjusted): 2023 and 2024

	2023			2024		
	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)	($0.14)	($0.23)	($0.41)	$0.29	($1.13)
AEP	$0.89	$1.47	$0.31	$0.17	$0.92	($0.60)
APS	$0.96	$1.62	$0.29	($0.11)	$0.57	($0.79)
ATSI	$0.88	$1.49	$0.27	$0.04	$0.83	($0.75)
BGE	$1.79	$2.79	$0.78	$1.10	$1.78	$0.41
COMED	$0.54	$1.02	$0.06	($0.16)	$0.46	($0.79)
DAY	$0.97	$1.50	$0.44	($0.10)	$0.57	($0.78)
DOM	$1.37	$2.25	$0.50	$0.31	$0.94	($0.32)
DPL	($0.44)	($0.61)	($0.26)	($0.36)	$0.25	($0.99)
DUKE	$0.97	$1.55	$0.38	($0.41)	$0.31	($1.15)
DUQ	$0.92	$1.52	$0.31	($0.22)	$0.41	($0.86)
EKPC	$0.96	$1.60	$0.31	($0.42)	$0.13	($0.99)
JCPLC	($0.17)	($0.08)	($0.26)	($0.52)	$0.20	($1.25)
MEC	$0.05	$0.48	($0.37)	($0.66)	$0.10	($1.43)
OVEC	$0.92	$1.50	$0.33	($0.45)	$0.01	($0.91)
PE	$0.65	$1.10	$0.19	($0.28)	$0.33	($0.91)
PECO	($0.32)	($0.42)	($0.23)	($0.44)	$0.16	($1.05)
PEPCO	$1.51	$2.47	$0.54	$0.62	$1.15	$0.09
PPL	($0.13)	$0.09	($0.34)	($0.80)	($0.20)	($1.41)
PSEG	($0.18)	($0.09)	($0.27)	($0.43)	$0.37	($1.24)
REC	($0.02)	$0.17	($0.20)	($0.27)	$0.39	($0.94)

Table 3-131 Real-time average zonal markup component (Adjusted): 2023 and 2024

	2023			2024		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$1.27	$1.43	$1.11	$1.35	$2.18	$0.51
AEP	$2.90	$3.69	$2.11	$2.16	$3.12	$1.20
APS	$3.00	$3.86	$2.12	$1.97	$2.87	$1.05
ATSI	$2.86	$3.69	$2.03	$2.06	$3.09	$1.03
BGE	$4.20	$5.45	$2.94	$3.47	$4.44	$2.49
COMED	$2.43	$3.17	$1.69	$1.62	$2.45	$0.78
DAY	$3.06	$3.80	$2.30	$1.95	$2.83	$1.06
DOM	$3.63	$4.76	$2.50	$2.53	$3.39	$1.66
DPL	$1.10	$1.07	$1.13	$1.51	$2.26	$0.74
DUKE	$3.00	$3.79	$2.20	$1.56	$2.48	$0.62
DUQ	$2.89	$3.71	$2.06	$1.80	$2.69	$0.91
EKPC	$2.98	$3.82	$2.12	$1.55	$2.31	$0.78
JCPLC	$1.35	$1.57	$1.13	$1.26	$2.10	$0.41
MEC	$1.76	$2.38	$1.14	$1.20	$2.15	$0.24
OVEC	$2.90	$3.69	$2.12	$1.48	$2.13	$0.83
PE	$2.52	$3.17	$1.87	$1.73	$2.57	$0.89
PECO	$1.06	$1.06	$1.05	$1.28	$2.00	$0.55
PEPCO	$3.78	$4.97	$2.58	$2.92	$3.70	$2.12
PPL	$1.45	$1.84	$1.05	$0.98	$1.75	$0.20
PSEG	$1.35	$1.57	$1.13	$1.36	$2.26	$0.44
REC	$1.62	$1.94	$1.29	$1.59	$2.35	$0.81

201 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.

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Markup by Real-Time Price Levels

Table 3-132 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 3-132 Real-time markup contribution (By load-weighted LMP category, unadjusted): 2023 and 2024

	2023		2024	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($3.14)	0.7%	($1.92)	1.4%
$10 to $15	($1.31)	6.2%	($1.93)	11.4%
$15 to $20	($1.29)	17.7%	($2.37)	17.6%
$20 to $25	($1.25)	22.2%	($2.05)	18.4%
$25 to $50	$0.66	45.3%	($0.17)	40.8%
$50 to $75	$7.92	5.7%	$4.85	6.3%
$75 to $100	$15.62	1.4%	$6.96	1.8%
$100 to $125	$19.62	0.4%	$6.15	1.1%
$125 to $150	$28.94	0.2%	$16.63	0.5%
>= $150	$9.70	0.2%	$28.62	0.8%

Table 3-133 Real-time markup contribution (By load-weighted LMP category, adjusted): 2023 and 2024

	2023		2024	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($2.24)	0.7%	($1.15)	1.4%
$10 to $15	($0.20)	6.2%	($0.87)	11.4%
$15 to $20	$0.10	17.7%	($1.02)	17.6%
$20 to $25	$0.43	22.2%	($0.40)	18.4%
$25 to $50	$2.85	45.3%	$2.09	40.8%
$50 to $75	$10.65	5.7%	$7.80	6.3%
$75 to $100	$18.22	1.4%	$10.08	1.8%
$100 to $125	$21.94	0.4%	$9.88	1.1%
$125 to $150	$33.23	0.2%	$20.76	0.5%
>= $150	$11.56	0.2%	$31.50	0.8%

Markup by Company

Table 3-134 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 2024, when using unadjusted cost-based offers, the markup of one company accounted for 2.1 percent of the load-weighted average LMP, the markup of the top five companies accounted for 4.7 percent of the load-weighted average LMP and the markup of all companies accounted for less than one percent of the load-weighted average LMP. The share of top five companies' markup contribution to the load-weighted average LMP increased and the dollar values of their markup increased in 2024. The markup contribution to the load-weighted average LMP decreased and share of the markup contribution to the load-weighted average LMP decreased 2024. The markup contribution of a unit to the real-time load-weighted average LMP can be positive or negative.

Table 3-134 Markup component of real-time load-weighted average LMP by Company: 2023 and 2024

	2023				2024			
	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	$0.94	3.0%	$1.15	3.7%	$0.71	2.1%	$0.90	2.7%
Top 2 Companies	$1.10	3.5%	$1.46	4.7%	$1.06	3.1%	$1.41	4.2%
Top 3 Companies	$1.24	4.0%	$1.66	5.3%	$1.24	3.7%	$1.78	5.3%
Top 4 Companies	$1.35	4.3%	$1.83	5.9%	$1.42	4.2%	$1.98	5.9%
Top 5 Companies	$1.44	4.6%	$1.97	6.3%	$1.58	4.7%	$2.16	6.4%
All Companies	$0.73	2.3%	$2.67	8.6%	($0.01)	(0.0%)	$1.98	5.9%

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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:[202]

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

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

The PJM energy market HHIs and application of the FERC concentration categories understate the degree of market power because, in the absence of aggregate market power mitigation, even the unconcentrated HHI level implies substantial markups due to the low short run price elasticity of demand. For example, research estimates find short run electricity demand elasticity ranging from -0.2 to -0.4.[203] 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:[204]

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

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 $33.74 per MWh and an average HHI of 714 in 2024, average PJM prices would theoretically range from $41 to $53 per MWh, an implied markup of 17.9 to 35.7 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 absence of market power mitigation. Actual prices, averaging $33.74 per MWh with markups at -0.1 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.

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

203 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>.

204 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.

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Table 3-135 categorizes day-ahead and real-time marginal unit intervals by markup level and TPS test status. In 2024, 3.4 percent of real-time marginal unit intervals and 4.3 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.

Table 3-135 Percent of real-time marginal unit intervals with markup and local market power: 2024

	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	34.1%	4.5%	38.6%	48.7%	7.5%	56.2%
Zero Markup	19.7%	6.1%	25.8%	18.8%	5.8%	24.6%
$0 to $5	12.3%	1.4%	13.7%	8.9%	1.7%	10.6%
$5 to $10	7.8%	1.4%	9.2%	3.3%	0.6%	4.0%
$10 to $15	2.0%	0.5%	2.4%	1.1%	0.3%	1.4%
$15 to $20	1.4%	0.3%	1.6%	0.5%	0.2%	0.7%
$20 to $25	0.7%	0.2%	0.9%	0.3%	0.1%	0.3%
$25 to $50	3.9%	0.5%	4.3%	1.3%	0.3%	1.6%
$50 to $75	2.0%	0.1%	2.1%	0.1%	0.1%	0.2%
$75 to $100	1.0%	0.0%	1.0%	0.1%	0.1%	0.1%
Above $100	0.3%	0.0%	0.3%	0.1%	0.1%	0.2%
Total Positive Markup	31.3%	4.3%	35.6%	15.8%	3.4%	19.2%
Total	85.1%	14.9%	100.0%	83.4%	16.6%	100.0%

The markup of marginal units was zero or negative in 80.8 percent of real-time marginal unit intervals and 64.4 percent of day-ahead marginal unit intervals in 2024. 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 2024. The 31.3 percent of day-ahead marginal units and 15.8 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.

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