

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 2022.

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 67 percent of days. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM aggregate energy market in 2022 was, on average, unconcentrated by FERC HHI standards. The average HHI was 700 with a minimum of 554 and a maximum of 1012 in 2022. The baseload segment of the supply curve was unconcentrated. The intermediate segment of the supply curve was moderately concentrated. The peaking segment of the supply curve was highly concentrated. The fact that the average HHI is in the unconcentrated range does not mean that the aggregate market was competitive in all hours. As demonstrated for the day-ahead market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints and local reliability issues. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. Transmission constraints create the potential for the exercise of local market power. The goal of PJM's application of the three pivotal supplier test is to identify local market power and offer cap to competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the definition of cost-based offers and the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed because unit owners can exercise market power even when they fail the TPS test.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the day-ahead and real-time energy markets, although the behavior of some participants both routinely and during periods of high demand represents economic withholding. The ownership of marginal units is concentrated. The markups of pivotal suppliers in the aggregate market and of many pivotal suppliers in local markets remain unmitigated due to the lack of aggregate market power mitigation and the flawed implementation of offer caps for resources that fail the TPS test. The markups of those participants affected LMP.
- Market performance was evaluated as competitive because market results in the energy market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both day-ahead and real-time energy markets, although high markups for some marginal units did affect prices.
- Market design was evaluated as effective because the analysis shows that the PJM energy market

resulted in competitive market outcomes. In general, PJM's energy market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design identifies market power and causes the market to provide competitive market outcomes in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. The role of UTCs in the day-ahead energy market continues to cause concerns. Market design implementation issues, including inaccuracies in modeling of the transmission system and of generator capabilities as well as inefficiencies in real-time dispatch and price formation, undermine market efficiency in the energy market. PJM resolved the problems with real-time dispatch and pricing effective November 1, 2021. The implementation of fast start pricing on September 1, 2021, undermined market efficiency by setting inefficient prices that are inconsistent with the dispatch signals.

- PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's core functions is to identify actual or potential market design flaws.¹ The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on mitigating market power in instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. FERC relies on effective market power mitigation when it approves market sellers to participate in the PJM market at market based rates.² In the PJM energy market, market power mitigation occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator

offers would affect the market price.³ There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed. FERC recognized these issues in its June 17, 2021 order.⁴ Some units with market power have positive markups and some have inflexible parameters, which means that the cost-based offer was not used and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the rules permitting cost-based offers in excess of \$1,000 per MWh.

¹ OATT Attachment M (PJM Market Monitoring Plan).

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

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

⁴ 175 FERC ¶ 61,231 (2021).

Overview

Supply and Demand

Market Structure

- **Supply.** In 2022, 4,978 MW of new resources were added in the energy market, and 6,164 MW of resources were retired.
- The real-time hourly on peak average offered supply was 136,184 MW in 2021, and 137,869 MW in 2022. The day-ahead hourly on peak average offered supply was 155,811 MW in 2021, and 152,314 MW in 2022.
- The real-time hourly average cleared generation in 2022 increased by 0.8 percent from 2021, from 93,644 MWh to 94,368 MWh.
- The day-ahead hourly average supply in 2022, including INCs and UTCs, increased by 8.4 percent from 2021, from 102,431 MWh to 111,044 MWh.
- **Demand.** The real-time hourly peak load plus exports in 2022 was 149,531 MWh (144,356 MWh of load plus 5,175 MWh of gross exports) in the HE 1800 (EPT) on July 20, 2022, which was 1.4 percent, 2,150 MWh, lower than the PJM peak load plus exports in 2021, which was 151,680 MWh in the HE 1800 (EPT) on August 24, 2021.
- The real-time hourly average load in 2022 increased by 1.5 percent from 2021, from 87,606 MWh to 88,884 MWh.
- The day-ahead hourly average demand in 2022, including DEC and UTCs, increased by 8.4 percent from 2021, from 97,537 MWh to 105,715 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 37.3 percent and cleared increment MW increased by 55.2 percent in 2022 compared to 2021. The hourly average submitted decrement bid MW increased by 21.8 percent and cleared decrement MW increased by 21.3 percent in 2022 compared to 2021. The hourly average submitted up to congestion bid

MW increased by 137.4 percent and cleared up to congestion bid MW increased by 87.8 percent in 2022 compared to 2021.

Market Performance

- **Generation Fuel Mix.** In 2022, generation from coal units decreased 9.1 percent, generation from natural gas units increased 6.8 percent, and generation from oil increased 17.8 percent compared to 2021. Wind and solar output rose by 16.2 percent compared to 2021, supplying 6.8 percent of PJM energy in 2022.
- **Fuel Diversity.** The fuel diversity of energy generation in 2022, measured by the fuel diversity index for energy (FDI_e), decreased 0.7 percent compared to 2021.
- **Marginal Resources.** In the PJM Real-Time Energy Market in 2022, coal units were 10.0 percent and natural gas units were 75.2 percent of marginal resources. In 2021, coal units were 14.1 percent and natural gas units were 71.7 percent of marginal resources.

In the PJM Day-Ahead Energy Market in 2022, UTCs were 49.0 percent, INCs were 16.3 percent, DEC were 18.8 percent, and generation resources were 15.6 percent of marginal resources. In 2021, UTCs were 35.2 percent, INCs were 17.9 percent, DEC were 27.1 percent, and generation resources were 19.5 percent of marginal resources.

- **Prices.** The real-time load-weighted average LMP in 2022 increased 101.4 percent from 2021, from \$39.78 per MWh to \$80.14 per MWh.
- The day-ahead load-weighted average LMP in 2022 increased 91.6 percent from 2021, from \$39.37 per MWh to \$75.44 per MWh.
- **Fast Start Pricing.** The real-time load-weighted average PLMP was \$80.14 per MWh for 2022, which is 5.0 percent, \$3.80 per MWh, higher than the real-time load-weighted average DLMP of \$76.34 per MWh.
- **Components of LMP.** In the PJM Real-Time Energy Market in 2022, 7.1 percent of the load-weighted LMP was the result of coal costs, 51.7 percent was the result of gas costs and 4.9 percent was the result of the cost of emission allowances. In 2022, 5.8 percent of load-weighted LMP was the result of transmission constraint violation penalty factors.

In 2022, 2.8 percent of the real-time load-weighted average LMP was the result of the commitment costs of fast start units.

Of the \$40.36 per MWh increase in the real-time load weighted average LMP, \$22.82 per MWh (56.6 percent) was in the fuel and consumables cost components of LMP, \$3.71 per MWh (9.2 percent) was in the emissions cost components of LMP, \$4.83 per MWh (12.0 percent) was in the sum of the markup, maintenance, and ten percent adder components of LMP, \$1.11 per MWh (2.7 percent) was in the transmission constraint penalty factor component of LMP, and \$4.83 per MWh (12.0 percent) was in the scarcity component of LMP.

In the PJM Day-Ahead Energy Market in 2022, 23.0 percent of the load-weighted LMP was the result of gas costs, 8.4 percent was the result of coal costs, 15.9 percent was the result of DEC bids, 26.2 percent was the result of INC offers, 7.3 percent was the result of positive markup, and 7.8 percent was the result of UTCs. In 2022, 0.6 percent of the day-ahead load-weighted average LMP was the result of commitment costs.

Of the \$36.07 per MWh increase in the day-ahead load weighted average LMP, \$20.76 per MWh (57.6 percent) was in the virtual and dispatchable transactions cost components of LMP, \$7.12 per MWh (19.7 percent) was in the fuel and consumables cost components of LMP, \$1.50 per MWh (4.1 percent) was in the emissions cost components of LMP, \$5.62 per MWh (15.6 percent) was in the sum of the markup, maintenance, and ten percent adder components of LMP.

- **Price Convergence.** Hourly and daily price differences between the day-ahead and real-time energy markets fluctuate continuously and substantially from positive to negative. The difference between day-ahead and real-time average prices was \$2.76 per MWh in 2022, and \$0.42 per MWh in 2021. The difference between day-ahead and real-time average prices, by itself, is not a measure of the competitiveness or effectiveness of the day-ahead energy market.

Scarcity

- There were 270 intervals with five minute shortage pricing on 22 days in 2022. There were local load

shed directives and dispatch of pre-emergency and emergency load management reduction actions in the Marion area of AEP that resulted in Performance Assessment Intervals on three days in June 2022. In December 2022 during Winter Storm Elliott (Elliott), there was a period of cold weather and widespread outages, during which PJM triggered pre-emergency and emergency load management reduction actions and maximum emergency generation actions that resulted in Performance Assessment Intervals on December 23 and December 24.

- There were 9,026 five minute intervals, or 8.6 percent of all five minute intervals, in 2022 for which at least one RT SCED solution showed a shortage of reserves, and 2,776 five minute intervals, or 2.6 percent of all five minute intervals, in 2022 for which more than one RT SCED solution showed a shortage of reserves. PJM triggered shortage pricing for 270 five minute intervals, or 0.3 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 245 days, 67.1 percent of days, in 2022 and 286 days, 78.4 percent of days, in 2021.
- **Local Market Power.** In 2022, in the real-time market, ten zones 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 2022, the average number of suppliers providing constraint relief was three or fewer. There was a high level of concentration within the local markets for providing relief to the most congested facilities in the PJM Real-Time Energy Market. The local market structure was not competitive.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means

of addressing local market power when the rules are designed and implemented properly. Offer capping levels have historically been low in PJM. In the day-ahead energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 1.6 percent in 2021 to 1.7 percent in 2022. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.5 percent in 2021 to 1.3 percent in 2022. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have had a significant impact on prices in the absence of local market power mitigation.

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

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, including for reactive support. In the day-ahead energy market, for units committed for reliability reasons, offer-capped unit hours increased from 0.02 percent in 2021 to 0.04 percent in 2022. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours increased from 0.03 percent in 2021 to 0.05 percent in 2022. The low offer cap percentages do not mean that units manually committed for reliability reasons do not have market power. All units manually committed for reliability have market power and all are treated as if they had market power. These units are not capped to their cost-based offers because they tend to offer with a negative markup in their price-based offers, particularly at the economic minimum level, which means that PJM's offer capping process results in the use of the price-based offer for commitment even if it has less flexible operating parameters.
- **Parameter Mitigation.** In 2022, 30.6 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. In 2022, on days when cold weather alerts and hot weather alerts were declared, 33.4 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 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 0.16 in 2022, some marginal units did have substantial markups. The highest markup for any marginal unit in the real-time market in 2022 was more than \$900 per MWh when using unadjusted cost-based offers.

While the average markup index in the day-ahead market was 0.46 in 2022, some marginal units did have substantial markups. The highest markup for any marginal unit in the day-ahead market in 2022 was more than \$300 per MWh when using unadjusted cost-based offers.

- **Markup.** The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power.

Market Performance

- **Markup.** The markup conduct of individual owners and units has an identifiable impact on market prices. Markup is a key indicator of the competitiveness of the energy market.

In the PJM Real-Time Energy Market in 2022, the unadjusted markup component of LMP was \$3.32 per MWh or 4.1 percent of the PJM load-weighted average LMP. June had the highest unadjusted

peak markup component, \$10.12 per MWh, or 8.0 percent of the real-time peak hour load-weighted average LMP for June.

In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In 2022, the unadjusted markup component of LMP was \$4.47 per MWh or 5.9 percent of the PJM day-ahead load-weighted average LMP. November had the highest unadjusted peak markup component, \$9.05 per MWh, or 14.7 percent of the day-ahead peak hour load-weighted average LMP for November.

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 5.8 percent of all real-time marginal unit intervals in 2022, 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 2022, 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 25 days.

Recommendations

Market Power

- The MMU recommends that the market rules explicitly require that offers in the energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers not exceed the short run marginal cost of the

unit. (Priority: Medium. First reported 2009. Status: Not adopted.)

Fuel Cost Policies

- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy. (Priority: Low. First reported 2020. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy. (Priority: Medium. First reported 2020. Status: Not adopted.)

Cost-Based Offers

- The MMU recommends that Manual 15 (Cost Development Guidelines) be replaced or updated with a straightforward description of the components of cost-based offers and the mathematically correct calculation of cost-based offers. (Priority: Medium. First reported 2016. Status: Partially adopted Q1 2022.)⁵
- 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.)

⁵ Manual 15 has been updated with the correct calculations and descriptions of the cost components for incremental energy offers and no load costs. The start cost calculations have not been approved.

- 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: Not adopted.)
- The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of the operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Partially Adopted.)
- The MMU recommends that soak costs, soak time and the MWh produced during soaking be modeled separately. This will ensure that the time required for units to reach a dispatchable level is known and used in the unit commitment process instead of only being communicated verbally 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. New recommendation. 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.)⁶
- The MMU recommends that PJM modify the process of applying the TPS test in the day-ahead energy market to ensure that all local markets created by binding constraints are tested for market power and to ensure that market sellers with market power are appropriately mitigated to their competitive offers. (Priority: High. First reported Q1 2022. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times. (Priority: High. First reported Q3 2021. Status: Not adopted.)
- The MMU recommends, if the preferred recommendation is not implemented, that in order to ensure effective market power mitigation, PJM always enforce parameter limited values when the TPS test is failed and during high load conditions such as cold and hot weather alerts and emergency conditions. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be consistently positive or negative

⁶ The real-time market formula for determining the lowest cost schedule is currently documented.

across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)

- The MMU recommends that PJM retain the \$1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed \$1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999, 2017.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)⁷

Offer Behavior

- The MMU recommends that resources not be allowed to violate the ICAP must offer requirement. The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that storage and intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM integrate all the outage reporting tools in order to enforce the ICAP must offer requirement, ensure that outages are reported correctly and eliminate reporting inconsistencies. Generators currently submit availability in three different tools that are not integrated, Markets Gateway, eDART and eGADS.

(Priority: Medium. New recommendation. Status: Not adopted.)

- The MMU recommends that gas generators be required to check with pipelines throughout the operating day to confirm that nominations are accepted beyond the NAESB deadlines, and that gas generators be required to place their units on forced outage until the time that pipelines allow nominations to consume gas at a unit. (Priority: Medium. First reported Q1 2022. Status: Not adopted.)

Capacity Resources

- The MMU recommends that capacity resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity market design. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity resource performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)⁸
- 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.)

⁷ 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.

⁸ 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.

- The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits. (Priority: Medium. First reported 2018. Status: Not adopted.)
 - The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not enforced at the time, or are based on inferior transportation service procured by the generator. (Priority: Medium. First reported 2019. Status: Not adopted.)
 - The MMU recommends that PJM require generators that violate their approved turn down ratio (by either using the fixed gen option or increasing their economic minimum) to use the temporary parameter exception process that requires market sellers to demonstrate that the request is based on a physical and actual constraint. (Priority: Medium. First reported 2021. Status: Not adopted.)
 - The MMU recommends: that gas generators be required to confirm, regularly during the operating day, that they can obtain gas if requested to operate at their economic maximum level; that gas generators provide that information to PJM during the operating day; and that gas generators be required to be on forced outage if they cannot obtain gas during the operating day to meet their must offer requirement as a result of pipeline restrictions, and they do not have backup fuel. As part of this, the MMU recommends that PJM collect data on each individual generator's fuel supply arrangements at least annually or when such arrangements change, and analyze the associated locational and regional risks to reliability. (Priority: Medium. First reported Q1 2022. Status: Not adopted.)
 - The MMU recommends, if the capacity market seller offer cap were to be calculated using the historical average balancing ratio, that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs), and only include those events that trigger emergencies at a defined zonal or higher level. (Priority: Medium. First reported 2018. Status: Not adopted.)
- the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation and when the transmission penalty factors will be used to set the shadow price. The MMU recommends that PJM end the practice of discretionary reductions in transmission line ratings modeled in the market clearing and included in LMP. (Priority: Medium. First reported 2015. Status: Partially adopted 2020.)⁹
- 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 2013.¹⁰ (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

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;

⁹ PJM created a more transparent process for transmission constraint penalty factors and added it to the tariff in 2020. Policies on line rating reductions (including limit control percentage) and the duration of violations remain discretionary and undocumented in the PJM Market Rules.

¹⁰ This recommendation was the result of load shed events in September, 2013. For detailed discussion, please see 2013 *State of the Market Report for PJM*, Volume II, Section 3 at 114 – 116.

definitions have changed.^{11 12} (Priority: Low. First reported 2013. Status: Not adopted.)

- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the coordination of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions, including soak time for units with a steam turbine, configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)

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

Transparency

- The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM manuals, including defining all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule availability on an hourly basis. (Priority: Medium. First reported 2015. Status: Partially adopted.)¹³
- 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.)¹⁴

¹¹ 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.

¹² 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>>.

¹³ Fuel type is reported by offer schedule, but it can be inaccurate on an hourly basis.

¹⁴ 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.

Virtual Bids and Offers

- The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues. (Priority: Medium. First reported 2020. Status: Not adopted.)

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in 2022, 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 2022, both the price level and the price increase over 2021 were the highest since the PJM market was created in 1999. The largest contributor to increased prices was the cost of fuel, primarily natural gas and coal. The fuel cost components of LMP (the sum of gas, coal, oil, landfill gas, and consumables) increased \$22.82 per MWh, 56.6 percent of the increase in LMP. The emissions cost components of LMP increased by \$3.71 per MWh, 9.2 percent of the increase in LMP, mostly due to high NO_x prices during the summer. New limitations on natural gas plants in Illinois and high NO_x emissions allowance prices contributed to higher LMPs. Administrative pricing was a significant addition to prices, particularly during Elliott. On December 23 and December 24, 70 percent of the load-weighted LMP was the result of administrative pricing adders. The scarcity component of LMP at \$4.83 per MWh, minus the \$1.39 per MWh effect of price capping, plus the demand response strike price at \$1.75 per MWh, plus the transmission constraint penalty factor at \$1.11 per MWh, contributed a total of 6.3 percent of the increase in LMP.

The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in 2022 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 2022, economic withholding affected prices through marginal units using increased price markups and a ten percent cost adder applied to a higher fuel cost. The markup, ten percent adder, and maintenance cost components, together increased by \$4.83 per MWh or 12.0 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.¹⁵ 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. In July, August, and September of 2022, PJM approved a shortage case for one RT SCED five minute interval out of 673 intervals with multiple shortage solutions, while the same months in 2021 had only 404 intervals with multiple shortage solutions and nine approved shortage intervals. During Elliott, PJM approved 45.4 percent of SCED shortage solutions. The pattern of shortage case approvals indicates that PJM considers factors other than RT SCED producing a shortage case when deciding whether to approve shortage cases.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised and ensure no scarcity pricing when such pricing is not consistent with market conditions. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy, as in PJM's 2019 ORDC proposal, is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity

¹⁵ 177 FERC ¶ 61,209 (2021).

pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent prices, that scarcity pricing only occurs when scarcity exists, that scarcity pricing not be excessive or punitive, and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets.

The PJM defined inputs to the dispatch tools, particularly the RT SCED, have substantial effects on energy market outcomes. Transmission line ratings, transmission penalty factors, load forecast bias, and hydro resource schedules change the dispatch of the system, affect prices, and can create significant price increases, particularly through transmission line limit violations. PJM operator interventions to reduce line ratings unnecessarily trigger transmission constraint penalty factors and significantly increase prices. Violations of reduced line limits had a direct effect on higher LMP in 2022. If the line limits had not been reduced for the PJM transmission constraints and everything else remained unchanged, fewer constraints would have been violated and the transmission penalty factor's contribution to the load weighted average LMP in 2022 would have decreased by 102.2 percent from \$4.63 to -\$0.10 per MWh. PJM should evaluate its interventions in the market, consider whether the interventions are appropriate, and provide greater transparency to enhance market efficiency.

Fast start pricing, implemented on September 1, 2021, has disconnected pricing from dispatch instructions and created a greater reliance on uplift rather than price as an incentive to follow PJM's instructions. The objective 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.¹⁶ The tradeoff exists because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal

for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. Units that start in one hour are not actually fast start units, and their commitment costs are not marginal in a five minute market. The differences between the actual LMP and the fast start LMP will distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions. PJM is paying new forms of uplift in an attempt to counter the distorted incentives inherent in fast start pricing. PJM is also using the pricing run to implement other differences from the dispatch run that are not related to fast start pricing, including differences in transmission constraint penalty factors and system marginal price capping. Every difference between the dispatch run and the pricing run introduces another inefficiency in the market.

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

The relationship between supply and demand, regardless of the specific market, along with market concentration and the extent of pivotal suppliers, is referred to as the supply-demand fundamentals

¹⁶ See 173 FERC ¶ 61,244 (2020).

or economic fundamentals or market structure. The market structure of the PJM aggregate energy market is partially competitive because aggregate market power does exist for a significant number of hours. The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. It is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. Even a low HHI may be consistent with the exercise of market power with a low price elasticity of demand. The current market power mitigation rules for the PJM energy market rely on the assumption that the ownership structure of the aggregate market ensures competitive outcomes. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market at times. High markups for some units demonstrate the potential to exercise market power both routinely and during high demand conditions. The existing market power mitigation measures do not address aggregate market power. The MMU is developing an aggregate market power test and will propose market power mitigation rules to address aggregate market power.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.¹⁷ However, there are some issues with the application of market power mitigation in the day-ahead energy market and the real-time energy market when market sellers fail the TPS test. The Commission recognized some of these issues in its order issued on June 17, 2021.¹⁸ PJM continues to ignore the evidence cited by the Commission and denies the prevalence of these issues, instead of ensuring that market power mitigation works as intended and results in efficient market outcomes.¹⁹ 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 continues to recommend them.²⁰ The

MMU recommendations would shorten the solution time of the day-ahead market software, which would help facilitate enhanced combined cycle modelling. PJM proposes to weaken market power mitigation as part of implementing the enhanced combined cycle modelling project. PJM's proposals would ensure that the identified issues with the implementation of market power mitigation in the energy market would never be addressed and would be exacerbated.

The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. A competitive offer is equal to short run marginal costs. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, under the PJM Market Rules, is not currently correct. The definition, that all costs that are related to electric production are short run marginal costs, is not clear or correct. All costs and investments for power generation are related to electric production. Under this definition, some unit owners include costs that are not short run marginal costs in offers, especially maintenance costs. This issue can be resolved by simple rule changes to incorporate a clear and accurate definition of short run marginal costs. This rule also had unintended consequences for market seller offer caps in the capacity market. Maintenance costs includable in energy offers cannot be included in capacity market offer caps based on avoidable costs. As a result, capacity market offer caps based on net avoidable costs were lower than they would have been if maintenance costs had been correctly included in avoidable costs rather than incorrectly defined to be part of short marginal costs of producing energy and includable in energy offers.

A competitive market requires that prices increase when fuel costs increase. A competitive market does not require that prices increase when markup increases or when PJM artificially triggers transmission constraint penalty factors. The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case in 2022 or prior years. Given the structure of the energy market which can permit the exercise of aggregate and local market power, the change in some participants' behavior is a source of concern in the

¹⁷ The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.

¹⁸ See 175 FERC ¶ 61,231 (2021).

¹⁹ See PJM, "Answer of PJM Interconnection LLC," Docket No. EL21-78 (September 15, 2021).

²⁰ See "Comments of the Independent Market Monitor for PJM," Docket No. EL21-78 (October 15, 2021).

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 2022.

Supply and Demand Market Structure

Supply

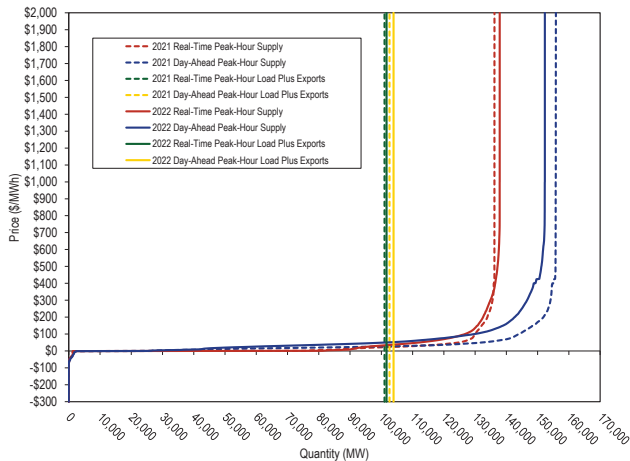
Supply includes physical generation, imports and virtual transactions.

In 2022, 4,978 MW of new resources were added in the energy market, and 6,164 MW of resources were retired.

Figure 3-1 shows real-time and day-ahead hourly supply curves in 2021 and 2022.^{21 22} The real-time supply curve includes hourly on peak average offers. The real-time supply curve includes available MW from units that are online or have a notification plus start time that is no more than one hour. The day-ahead supply curve shows all available hourly on peak average offers.

The real-time hourly on peak average offered supply was 136,184 MW in 2021, and 137,869 MW in 2022. The day-ahead hourly on peak average offered supply was 155,811 MW in 2021, and 152,314 MW in 2022.

Figure 3-1 Real-time and day-ahead hourly supply curves: 2021 and 2022



²¹ Real-time supply includes real-time generation offers and import MWh.
²² The supply curve period is from January 1 to December 31.

Figure 3-2 shows the typical dispatch range.

Figure 3-2 Typical dispatch range of supply curves

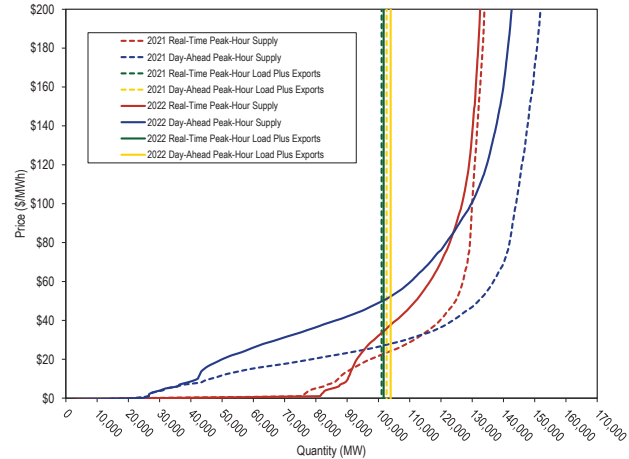


Table 3-2 shows the price elasticity of the real-time supply curve for the peak hours in 2021 and 2022 by load level.

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

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

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

Table 3-2 Price elasticity of the supply curve

	GW				
	Min - 75	75 - 95	95 - 115	115 - 135	135 - Max
2019	-	0.019	0.389	0.042	0.006
2020	0.021	0.213	0.348	0.031	0.003
2021	0.010	0.031	0.251	0.018	0.001
2022	-	0.007	0.175	0.027	0.006

Real-Time Supply

The real-time hourly average cleared generation in 2022 increased by 0.8 percent from 2021, from 93,644 MWh to 94,368 MWh.²³

The real-time hourly average cleared supply including imports in 2022 increased by 1.7 percent from 2021, from 94,501 MWh to 96,147 MWh.

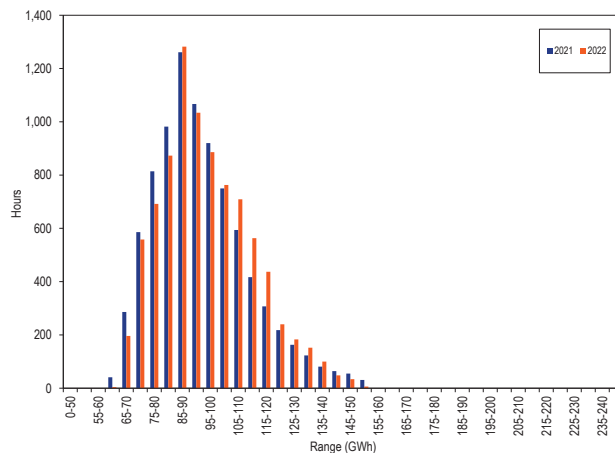
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **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 2021 and 2022.

Figure 3-3 Distribution of real-time generation plus imports: 2021 and 2022²⁴



²³ Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

²⁴ Each range on the horizontal axis excludes the start value and includes the end value.

PJM Real-Time Average Supply

Table 3-3 shows the real-time hourly average supply and its standard deviation for 2001 through 2022. The real-time hourly average cleared generation in 2022 increased by 0.8 percent from 2021, from 93,644 MWh to 94,368 MWh.

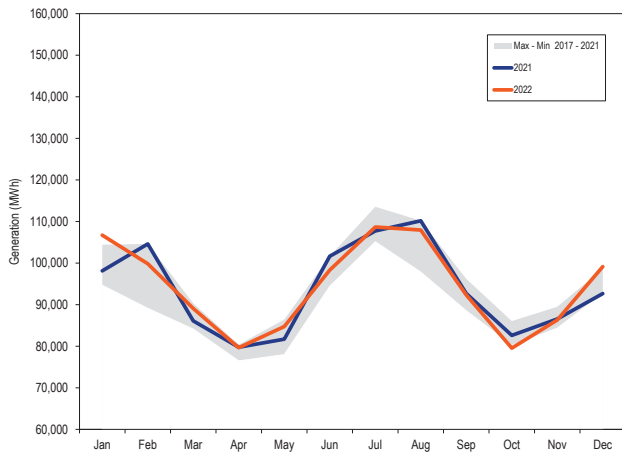
Table 3-3 Real-time hourly average generation and generation plus imports: 2001 through 2022

	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%)

PJM Real-Time Monthly Average Generation

Figure 3-4 compares the real-time monthly average generation in 2021 and 2022 with the historic five year range. In January and December 2022, the monthly average generation was higher than the maximum of the past five years, primarily as a result of weather related high demand. In October 2022, the monthly average generation was lower than the minimum of the past five years, primarily as a result of weather related low demand.

Figure 3-4 Real-time monthly average generation: 2021 and 2022



Day-Ahead Supply

The day-ahead hourly average supply in 2022, including INCs and UTCs, increased by 8.4 percent from 2021, from 102,431 MWh to 111,044 MWh.

The day-ahead hourly average supply in 2022, including INCs, UTCs and exports, increased by 8.5 percent from 2021, from 102,599 MWh to 111,353 MWh.

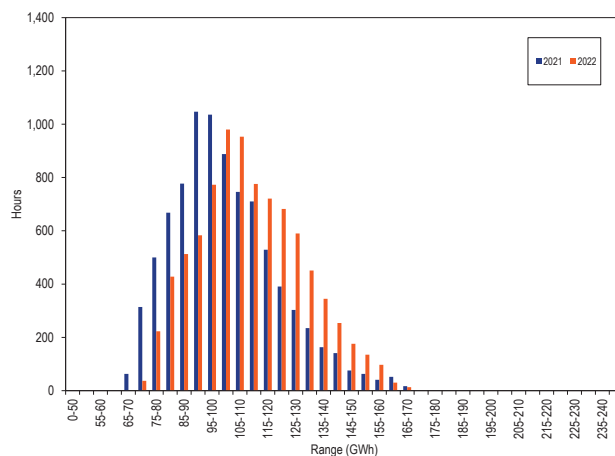
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **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 2021 and 2022.

Figure 3-5 Distribution of day-ahead cleared supply plus imports: 2021 and 2022²⁵



²⁵ 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 from 2001 through 2022. The day-ahead hourly average supply in 2022, including INCs and UTCs, increased by 8.4 percent from 2021, from 102,431 MWh to 111,044 MWh.

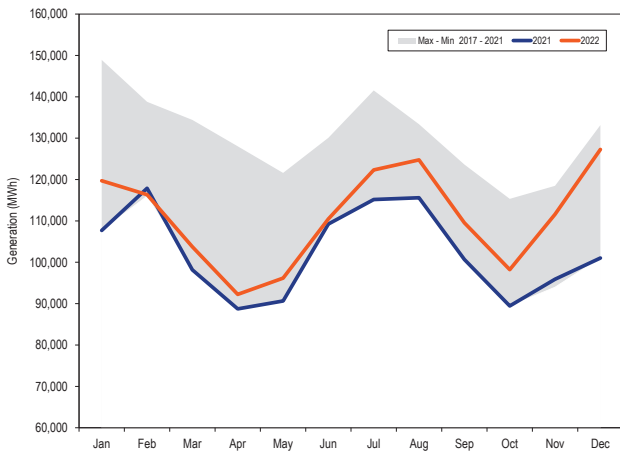
Table 3-4 Day-ahead hourly average cleared supply and cleared supply plus imports: 2001 through 2022

	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%

PJM Day-Ahead Monthly Average Cleared Supply

Figure 3-6 compares the day-ahead monthly average supply including increment offers and up to congestion transactions for 2021 and 2022 with the historic five year range.

Figure 3-6 Day-ahead monthly average cleared supply: 2021 and 2022



Real-Time and Day-Ahead Supply

Table 3-5 presents summary statistics for day-ahead and real-time cleared supply for 2021 and 2022. The last two columns of Table 3-5 are the day-ahead supply minus the real-time 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 supply less the total real-time supply. The total physical day-ahead average generation less the total physical real-time average generation in 2022 increased 435 MWh from 2021, from -575 MWh to -141 MWh. The total day-ahead average supply less the total real-time average supply in 2022 increased 7,108 MWh from 2021, from 8,098 MWh to 15,205 MWh.

Table 3-5 Day-ahead and real-time hourly supply (MWh): 2021 and 2022

		Day-Ahead			Real-Time		Day-Ahead Less Real-Time			
		Generation	INC Offers	Up to Congestion	Imports	Total Supply	Generation	Total Supply	Generation	Supply
Average	2021	93,069	2,312	7,050	168	102,599	93,644	94,501	(575)	8,098
	2022	94,227	3,578	13,239	308	111,353	94,368	96,147	(141)	15,205
Median	2021	90,444	2,222	6,833	106	99,893	90,902	91,800	(458)	8,093
	2022	91,269	3,488	11,659	265	109,319	91,906	93,418	(637)	15,901
Standard Deviation	2021	17,091	994	2,787	211	18,850	16,786	16,884	305	1,966
	2022	17,039	1,136	6,454	256	18,901	16,258	16,487	781	2,415
Peak Average	2021	101,851	2,794	8,072	164	112,880	101,997	102,919	(146)	9,961
	2022	101,983	3,972	14,146	358	120,460	101,740	103,645	244	16,815
Peak Median	2021	99,018	2,741	7,870	102	109,673	98,748	99,821	270	9,852
	2022	99,109	3,867	12,894	316	118,506	99,343	101,171	(234)	17,334
Peak Standard Deviation	2021	16,018	975	2,664	191	17,137	16,115	16,173	(97)	964
	2022	15,839	1,130	6,285	268	16,884	15,248	15,389	591	1,495
Off-Peak Average	2021	85,357	1,888	6,153	172	93,571	86,309	87,109	(952)	6,462
	2022	87,465	3,235	12,449	265	103,414	87,941	89,611	(475)	13,802
Off-Peak Median	2021	83,037	1,827	5,806	108	90,787	84,117	85,080	(1,080)	5,707
	2022	84,920	3,152	10,651	210	101,626	86,021	87,237	(1,101)	14,389
Off-Peak Standard Deviation	2021	14,005	797	2,576	227	15,334	13,643	13,742	363	1,592
	2022	15,053	1,024	6,497	237	16,879	14,263	14,513	790	2,366

Figure 3-7 shows the average cleared volumes of day-ahead and real-time supply by hour of the day in 2022. The day-ahead supply consists of cleared MW of physical generation, imports, increment offers and up to congestion transactions. The real-time supply consists of cleared MW of physical generation and imports.

Figure 3-7 Day-ahead and real-time supply (Average volumes by hour of the day): 2022

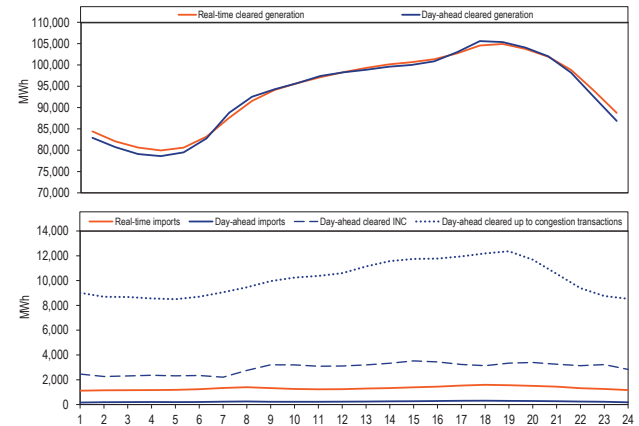
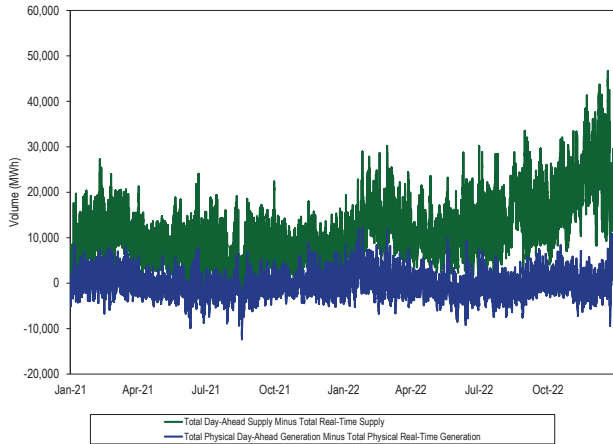


Figure 3-8 shows the difference between day-ahead and real-time daily average supply in 2021 and 2022.

Figure 3-8 Difference between day-ahead and real-time daily average supply: 2021 and 2022



Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

In this section, demand refers to accounting load and exports, and in the day-ahead energy market, includes virtual transactions.²⁶

Table 3-6 shows the peak load plus exports for 2009 through 2022. The real-time hourly peak load plus exports in 2022 was 149,531 MWh (144,356 MWh of load plus 5,175 MWh of gross exports) in the HE 1800 (EPT) on July 20, 2022, which was 1.4 percent, 2,150 MWh, lower than the PJM peak load plus exports in 2021, which was 151,680 MWh in the HE 1800 (EPT) on August 24, 2021.

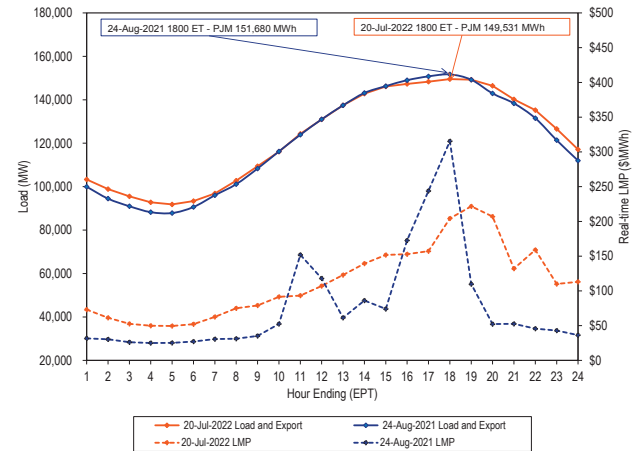
²⁶ PJM reports peak load including accounting load plus an addback equal to PJM's estimated load drop from demand side resources. This will generally result in PJM reporting peak load values greater than accounting load values. PJM's load drop estimate is based on PJM Manual 19: Load Forecasting and Analysis, Attachment A: Load Drop Estimate Guidelines.

Table 3-6 Actual footprint peak load plus export: 2009 through 2022^{27 28}

	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%)

Figure 3-9 compares prices and demand on the peak load days for 2021 and 2022. The real-time average LMP for August 24, 2021, peak load hour was \$315.42 per MWh, and for July 20, 2022, peak load hour it was \$204.29 per MWh.

Figure 3-9 Peak load and export day comparison



²⁷ 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.

²⁸ Peak loads shown have been corrected to reflect the accounting load value excluding PJM loss adjustment. The values presented in this table do not include settlement adjustments made prior to January 1, 2017.

Real-Time Demand

The real-time hourly average load in 2022 increased by 1.5 percent from 2021, from 87,606 MWh to 88,884 MWh.²⁹

The real-time hourly average demand including exports in 2022 increased by 1.6 percent from 2021, from 92,774 MWh to 94,301 MWh.

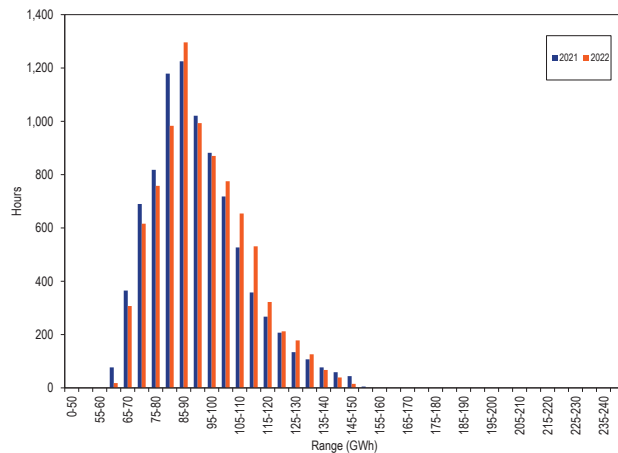
In the PJM Real-Time Energy Market, there are two types of demand:

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

PJM Real-Time Demand Duration

Figure 3-10 shows the distribution of the real-time hourly load plus exports for 2021 and 2022.³⁰

Figure 3-10 Distribution of real-time load plus exports: 2021 and 2022³¹



PJM Real-Time Average Load

Table 3-7 presents real-time hourly demand summary statistics for 2001 through 2022.³² The real-time hourly average load in 2022 increased by 1.5 percent from 2021, from 87,606 MWh to 88,884 MWh.

²⁹ Load data are the net MWh injections and withdrawals MWh at every load bus in PJM.

³⁰ 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>.

³¹ Each range on the horizontal axis excludes the start value and includes the end value.

³² 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.

Table 3-7 Real-time hourly average load and load plus exports: 2001 through 2022

	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%)

PJM Real-Time Monthly Average Load

Figure 3-11 compares the real-time monthly average load plus exports in 2021 and 2022, with the historic five year range. In December 2022, the monthly average load plus exports was higher than the maximum of the past five years, primarily as a result of weather related demand.

Figure 3-11 Real-time monthly average hourly load plus exports: 2021 and 2022

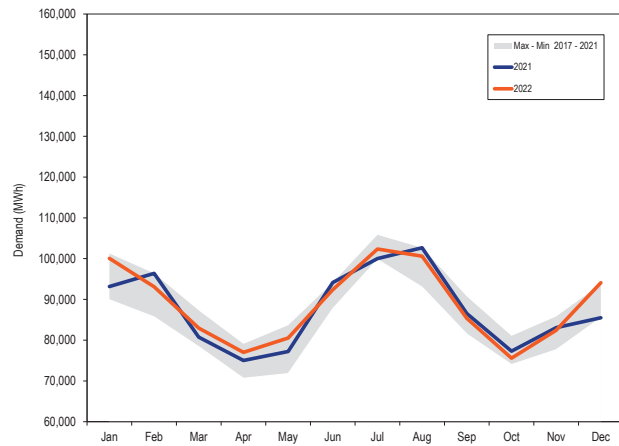
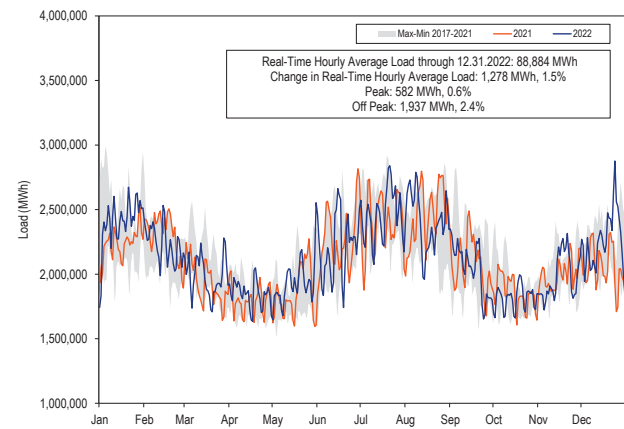


Figure 3-12 compares the real-time daily average load for 2021 and 2022, with the historic five year range.

Figure 3-12 Real-time daily load: 2021 and 2022



The real-time load is significantly affected by weather conditions. Table 3-8 compares the monthly heating and

cooling degree days in 2021 and 2022.³³ Cooling degree days decreased 2.7 percent compared to 2021. Heating degree days increased 9.5 percent compared to 2021.

Table 3-8 Heating and cooling degree days: 2021 and 2022

	2021		2022		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	815.9	0.0	982.8	0.0	20.5%	0.0%
Feb	822.1	0.0	693.1	0.0	(15.7%)	0.0%
Mar	404.9	0.0	445.1	0.0	9.9%	0.0%
Apr	203.1	8.1	255.7	4.8	25.9%	(41.1%)
May	77.1	81.6	21.2	100.6	(72.5%)	23.3%
Jun	0.0	283.1	0.0	260.2	0.0%	(8.1%)
Jul	0.0	360.1	0.0	406.2	0.0%	12.8%
Aug	0.0	373.8	0.0	345.4	0.0%	(7.6%)
Sep	0.0	157.7	15.4	152.8	0.0%	(3.1%)
Oct	56.7	44.0	164.2	0.0	189.6%	(100.0%)
Nov	490.7	0.0	386.1	3.0	(21.3%)	0.0%
Dec	524.0	0.0	752.2	0.0	43.5%	0.0%
Total	3,394.5	1,308.4	3,715.8	1,273.0	9.5%	(2.7%)

Figure 3-13 shows the real-time daily load and the weather normalized load in 2021 and 2022.

Weather normalized load is calculated using the historic relationship between the daily load and HDD, CDD, and time of year for 2015 through 2018. Figure 3-13 shows that the actual load was closer to the weather normalized load after a significant gap in 2020.

Figure 3-13 Real-time daily load and weather normalized load: 2020 through 2022

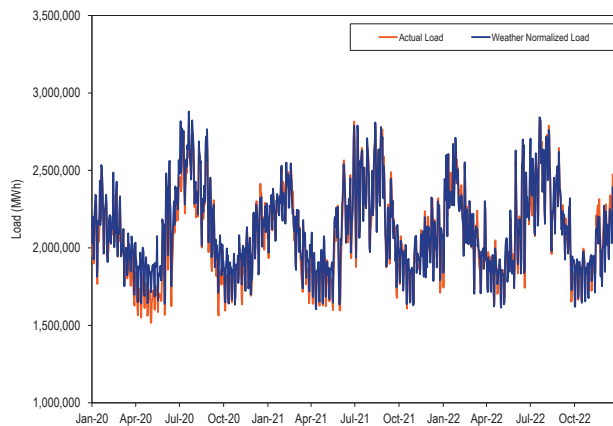


Table 3-9 compares the monthly actual load and the weather normalized load. Actual load was 0.2 percent higher than weather normalized load in 2022, actual load was 0.7 percent lower than weather normalized load in 2021, while actual load was 3.4 percent lower than weather normalized load in 2020.

³³ A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings). PJM uses 60 degrees F for a heating degree day as stated in Manual 19.

Heating and cooling degree days are calculated by weighting the temperature at each weather station in the individual transmission zones using weights provided by PJM in Manual 19. Then the temperature is weighted by the real-time zonal accounting load for each transmission zone. After calculating an average hourly temperature across PJM, the heating and cooling degree formulas are used to calculate the daily heating and cooling degree days, which are summed for monthly reporting. The weather stations that provided the basis for the analysis are ABE, ACY, AVP, BWI, CAK, CLE, CMH, CRW, CVG, DAY, DCA, ERI, EWR, FWA, IAD, ILG, IPT, LEX, ORD, ORF, PHL, PIT, RIC, ROA, TOL and WAL.

Table 3-9 Actual load and weather normalized load: 2020 to 2022

	2020			2021			2022		
	Actual Load	Weather Normalized Load	Percent Difference	Actual Load	Weather Normalized Load	Percent Difference	Actual Load	Weather Normalized Load	Percent Difference
Jan	66,905,774	68,256,113	(2.0%)	69,303,496	69,689,108	(0.6%)	74,457,669	73,965,891	0.7%
Feb	61,717,353	62,471,212	(1.2%)	64,761,103	64,275,946	0.8%	62,556,707	61,833,819	1.2%
Mar	58,258,178	60,459,812	(3.6%)	60,002,018	61,459,726	(2.4%)	61,629,282	61,986,274	(0.6%)
Apr	50,864,950	55,116,626	(7.7%)	54,010,529	55,580,210	(2.8%)	55,444,404	55,267,453	0.3%
May	53,430,088	57,904,128	(7.7%)	57,460,157	59,183,412	(2.9%)	59,904,861	59,795,738	0.2%
Jun	63,666,037	67,406,845	(5.5%)	67,779,457	68,488,450	(1.0%)	66,521,445	67,334,205	(1.2%)
Jul	78,749,183	80,856,404	(2.6%)	74,409,489	74,488,509	(0.1%)	76,153,249	76,721,135	(0.7%)
Aug	72,425,029	74,173,773	(2.4%)	76,383,295	76,161,192	0.3%	74,839,426	74,939,704	(0.1%)
Sep	58,683,018	60,988,913	(3.8%)	62,305,584	62,675,810	(0.6%)	61,451,519	62,081,806	(1.0%)
Oct	55,061,813	56,572,150	(2.7%)	57,511,887	57,304,504	0.4%	56,233,707	56,324,880	(0.2%)
Nov	55,993,432	57,678,640	(2.9%)	59,887,527	59,557,389	0.6%	59,428,403	59,060,319	0.6%
Dec	67,232,280	67,074,317	0.2%	63,610,554	64,276,557	(1.0%)	70,003,632	68,138,490	2.7%
Annual	61,915,595	64,079,911	(3.4%)	63,952,091	64,428,401	(0.7%)	64,885,359	64,787,476	0.2%

Day-Ahead Demand

The day-ahead hourly average demand in 2022, including DECs and UTCs, increased by 8.4 percent from 2021, from 97,537 MWh to 105,715 MWh.

The day-ahead hourly average demand in 2022, including DECs, UTCs and exports, increased by 8.4 percent from 2021, from 100,642 MWh to 109,119 MWh.

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

- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero.
- **Up to Congestion Transaction (UTC).** A conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up to congestion transaction is evaluated as a matched pair of an injection and a withdrawal.
- **Export.** An external energy transaction scheduled from PJM to another balancing authority. An export must have a valid willing to pay congestion (WPC) OASIS reservation when offered. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an export energy transaction approved in the day-ahead energy market will not physically flow in real-time unless it is also

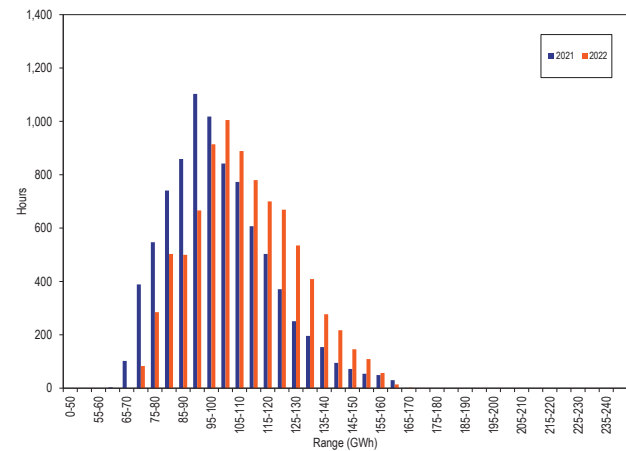
submitted through the real-time energy market scheduling process.

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

PJM Day-Ahead Demand Duration

Figure 3-14 shows the hourly distribution of the day-ahead demand for 2021 and 2022.

Figure 3-14 Distribution of day-ahead demand plus exports: 2021 and 2022³⁴



PJM Day-Ahead Average Demand

Table 3-10 shows day-ahead hourly average demand for 2001 through 2022. The day-ahead hourly average demand in 2022, including DECs and UTCs, increased by 8.4 percent from 2021, from 97,537 MWh to 105,715 MWh.

³⁴ Each range on the horizontal axis excludes the start value and includes the end value.

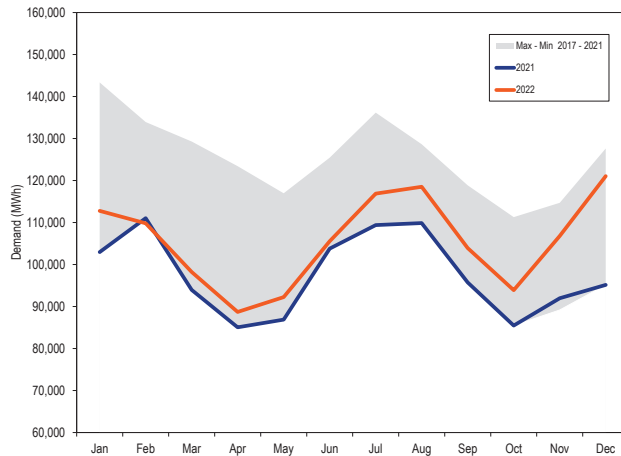
Table 3-10 Day-ahead hourly average demand and demand plus exports: 2001 through 2022

	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%

PJM Day-Ahead Monthly Average Demand

Figure 3-15 compares the day-ahead monthly average demand including decrement bids and up to congestion transactions in 2021 and 2022 with the historic five-year range.

Figure 3-15 Day-ahead monthly average demand plus exports: 2021 and 2022



Real-Time and Day-Ahead Demand

Table 3-11 presents summary statistics for day-ahead and real-time demand for 2021 and 2022. The last two columns of Table 3-11 are day-ahead demand minus real-time demand. The first column is the total physical day-ahead load (fixed demand plus price-sensitive demand) less the physical real-time load. The second column is the total day-ahead demand less the total real-time demand. The total physical day-ahead average load less the total physical real-time average load in 2022 decreased 174 MWh from 2021, from -1,324 MWh to -1,498 MWh. The total day-ahead average demand less the total real-time average demand in 2022 increased 6,949 MWh from 2021, from 7,868 MWh to 14,818 MWh.

Table 3-11 Day-ahead and real-time demand (MWh): 2021 and 2022

	Year	Day-Ahead					Real-Time		Day-Ahead Less Real-Time		
		Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Load	Demand
Average	2021	84,958	1,324	4,206	7,050	3,105	100,642	87,606	92,774	(1,324)	7,868
	2022	86,836	550	5,090	13,239	3,404	109,119	88,884	94,301	(1,498)	14,818
Median	2021	82,695	1,339	3,867	6,833	2,890	98,035	85,326	90,135	(1,292)	7,900
	2022	83,992	320	4,850	11,659	3,362	107,206	86,005	91,679	(1,692)	15,527
Standard Deviation	2021	15,109	273	1,808	2,787	1,047	18,359	15,725	16,485	(343)	1,874
	2022	15,529	402	1,685	6,454	1,006	18,393	15,689	16,047	243	2,346
Peak Average	2021	93,022	1,480	4,822	8,072	3,298	110,693	95,571	101,029	(1,070)	9,664
	2022	94,301	596	5,526	14,146	3,491	118,059	96,153	101,666	(1,257)	16,394
Peak Median	2021	90,401	1,508	4,530	7,870	3,061	107,544	92,729	97,940	(820)	9,604
	2022	91,539	316	5,339	12,894	3,456	116,172	93,506	99,248	(1,650)	16,924
Peak Standard Deviation	2021	13,959	222	1,774	2,664	1,143	16,669	14,889	15,769	(708)	900
	2022	14,283	440	1,643	6,285	1,002	16,411	14,610	14,974	112	1,437
Off-Peak Average	2021	77,876	1,187	3,665	6,153	2,936	91,816	80,610	85,524	(1,548)	6,292
	2022	80,328	511	4,709	12,449	3,329	101,325	82,547	87,881	(1,709)	13,444
Off-Peak Median	2021	75,817	1,221	3,317	5,806	2,762	89,149	78,721	83,528	(1,684)	5,621
	2022	78,056	323	4,444	10,651	3,290	99,598	80,094	85,654	(1,715)	13,944
Off-Peak Standard Deviation	2021	12,263	238	1,660	2,576	921	14,915	12,849	13,404	(348)	1,511
	2022	13,515	361	1,628	6,497	1,003	16,372	13,727	14,072	149	2,300

Figure 3-16 shows the average cleared volumes of day-ahead and real-time demand in 2022. The day-ahead demand includes day-ahead load, decrement bids, up to congestion transactions, and day-ahead exports. The real-time demand includes real-time load and real-time exports.

Figure 3-16 Day-ahead and real-time demand (Average hourly volumes): 2022

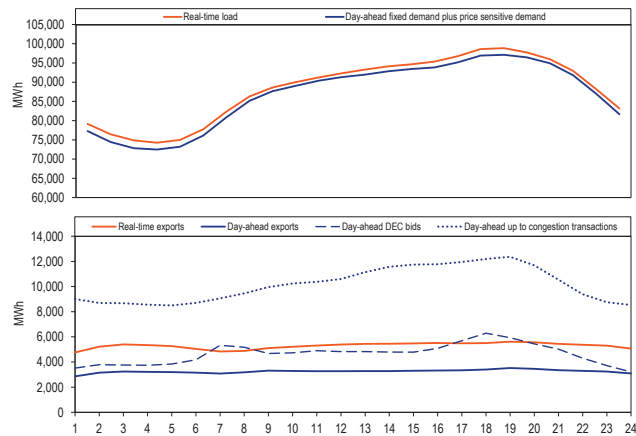
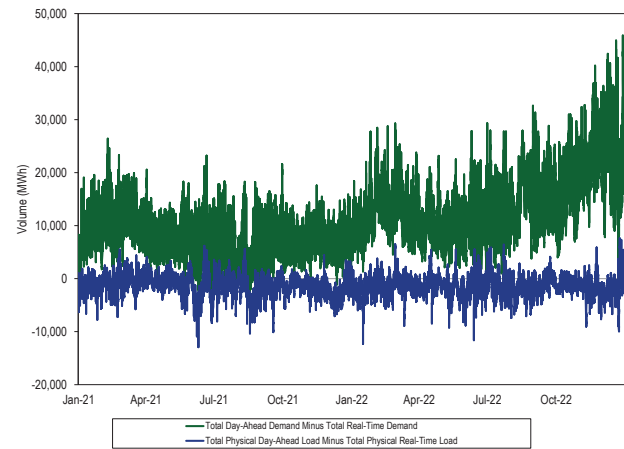


Figure 3-17 shows the difference between the day-ahead and real-time daily average demand in 2021 and 2022.

Figure 3-17 Difference between day-ahead and real-time daily average demand: 2021 and 2022



Market Behavior

Generator Offers

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

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

Units may designate all or a portion of their capacity as emergency MW. Table 3-12 shows that 0.8 percent of offered MW are emergency MW. In some cases, higher shares of emergency MW result from offer behavior that does not accurately represent the availability of the emergency MW in real time.

In the day-ahead market in 2022, 22.8 percent of MW were offered as must run, 31.6 percent of MW were offered as the economic minimum MW for dispatchable units, 44.7 percent of MW were offered as dispatchable, and 0.8 percent of MW were offered as emergency maximum MW.

In 2022, 47.6 percent of offer MW were priced below \$50 per MWh, compared to 62.3 percent in 2021. Higher fuel prices, emissions prices, opportunity costs for emissions limited resources, and markup all contributed to higher offers in 2022.

Table 3-12 Dispatchable status of day-ahead energy offers: 2022

Unit Type	Must Run	Eco Min	Dispatchable Range										Emergency MW	Dispatchable Percent
			(\$300 - \$0)	\$0 - \$25	\$25 - \$50	\$50 - \$75	\$75 - \$100	\$100 - \$200	\$200 - \$400	\$400 - \$600	\$600 - \$800	\$800 - \$1000		
CC	8.3%	35.5%	0.0%	3.9%	22.5%	14.0%	5.5%	6.5%	3.2%	0.3%	0.1%	0.0%	0.2%	56.0%
CT	0.4%	56.6%	0.0%	0.1%	2.0%	7.1%	7.3%	12.2%	9.3%	2.3%	0.6%	0.1%	2.0%	41.0%
Diesel	0.0%	91.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	8.1%	0.0%	0.0%	0.0%	0.0%	8.1%
Hydro	83.8%	0.0%	16.2%	0.0%	-0.0%	0.0%	-0.0%	0.0%	-0.0%	0.0%	-0.0%	-0.0%	0.0%	16.2%
Nuclear	89.6%	6.5%	2.8%	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.8%
Solar	13.3%	1.4%	78.2%	1.3%	0.6%	1.0%	1.1%	2.5%	0.6%	0.0%	0.0%	0.0%	0.0%	85.2%
Steam - Coal	25.5%	26.2%	0.0%	3.1%	15.1%	9.7%	8.2%	7.1%	1.4%	1.8%	0.0%	0.1%	1.9%	46.5%
Steam - Other	5.2%	23.0%	1.2%	1.5%	4.2%	9.4%	12.5%	17.8%	20.8%	3.8%	0.0%	0.1%	0.5%	71.3%
Wind	4.5%	0.7%	84.8%	4.8%	2.5%	1.1%	0.6%	0.6%	0.3%	0.0%	0.0%	0.0%	0.0%	94.8%
Other	16.9%	47.2%	5.0%	0.2%	5.2%	4.2%	0.2%	1.5%	14.9%	1.2%	0.2%	0.0%	3.4%	32.5%
All Units	22.8%	31.6%	2.6%	2.3%	11.2%	8.8%	5.9%	7.5%	5.1%	1.2%	0.2%	0.1%	0.8%	44.7%

Hourly Offers and Intraday Offer Updates

All participants may make hourly offers. Participants must opt in on a monthly basis to make intraday offer updates. Participants that have opted in can make updates only based on the process defined in their fuel cost policies. Table 3-13 shows the daily average number of units that make hourly offers, that opted in to intraday offer updates and that make intraday offer updates. In 2022, an average of 338 units per day made hourly offers, an increase of 12 units from 2021. In 2022, 491 units opted in for intraday offer updates, an increase of 54 units from 2021. In 2022, an average of 130 units made intraday offer updates each day, no change from 2021.

Table 3-13 Daily average number of units making hourly offers, opted in for intraday offers and making intraday offer updates: 2021 and 2022

	Fuel Type	2021	2022	Difference
Hourly Offers	Natural Gas	303	310	7
	Other Fuels	23	28	5
	Total	326	338	12
Opt In	Natural Gas	364	393	29
	Other Fuels	73	98	25
	Total	437	491	54
Intraday Offer Updates	Natural Gas	123	123	0
	Other Fuels	7	7	0
	Total	130	130	0
Total Units with nonzero offers		988	983	(5)

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.³⁵ 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.

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

The current enforcement of the ICAP must offer requirement is inadequate.³⁶ The problem is a complex

combination of generator behavior, and inadequate and inconsistent reporting tools that are not synchronized. Compliance is subject to mistakes and susceptible to manipulation.

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

For example, ambient ratings are an issue. When the weather is hotter than test conditions, the capacity of some units is reduced below the ICAP levels. While this fact may be reported by unit owners in eDART and reflected in lower offered MW in the energy market, the derates are not reported as outages in eGADS and are therefore not included as outages for purposes of defining capacity using EFORD. For planning purposes, PJM acknowledges this discrepancy, but instead of reflecting the derates in the supply offers from the units that are actually derated, PJM increases the demand for capacity to account for the loss of supply due to ambient derates.³⁷

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

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

Table 3-14 shows average hourly MW, for each month, that violated the ICAP must offer requirement in 2022. On average for all hours, 1,978 MW did not meet the ICAP must offer requirement, but for 10 percent of the hours 3,376 MW did not meet the must offer requirement. These MW levels are larger than the reserve shortages that triggered scarcity pricing in 2022 and larger than

³⁵ OA Schedule 1 § 1.10.1A(d).

³⁶ 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.

³⁷ 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>>.

most supply contingencies that led to synchronized reserve events in 2022.

Table 3-14 Average hourly estimated capacity (MW) failing the ICAP must offer requirement: 2022

Month	90 th Percentile	Average	10 th Percentile
Jan-22	1,595	927	434
Feb-22	1,632	1,034	471
Mar-22	3,463	2,145	868
Apr-22	1,809	1,255	763
May-22	3,300	1,972	810
Jun-22	2,880	1,712	925
Jul-22	3,424	2,682	1,938
Aug-22	3,137	2,372	1,656
Sep-22	2,057	1,129	0
Oct-22	3,083	2,164	1,402
Nov-22	3,899	3,046	2,179
Dec-22	4,254	3,183	2,280
2022	3,376	1,978	726

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.³⁸

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.³⁹

The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy.⁴⁰ Capacity resources should offer their full output in the energy market and subject to economic dispatch. The result will be incentives for correct reporting of ICAP, more efficient energy market pricing, and a reduction in the need for manual overrides by PJM dispatchers during emergency conditions. Resources that do have capacity that can only be achieved with extraordinary measures could offer such capacity in the energy market but should not take on a capacity market obligation.

Table 3-15 shows average hourly maximum emergency MW, for each month. The levels of maximum emergency MW change hourly, daily and seasonally. For example, in June 2022, 10 percent of hours had maximum emergency MW greater than or equal to 5,955 MW while 10 percent of hours had maximum emergency MW less than 3,639 MW. The hourly average, in 2022, was 2,405 MW offered as maximum emergency, 2.0 percent higher than in 2021.

Table 3-15 Maximum emergency MW by month: 2022

Month	90 th Percentile	Average	10 th Percentile
Jan-22	4,905	3,946	3,029
Feb-22	4,171	2,828	1,478
Mar-22	2,211	1,698	1,191
Apr-22	2,704	2,118	1,772
May-22	4,623	2,797	1,905
Jun-22	5,955	4,674	3,639
Jul-22	5,484	3,741	1,344
Aug-22	2,518	1,593	978
Sep-22	2,354	1,390	810
Oct-22	2,657	1,674	856
Nov-22	2,255	1,409	789
Dec-22	2,871	1,594	672
2022	4,191	2,405	1,227

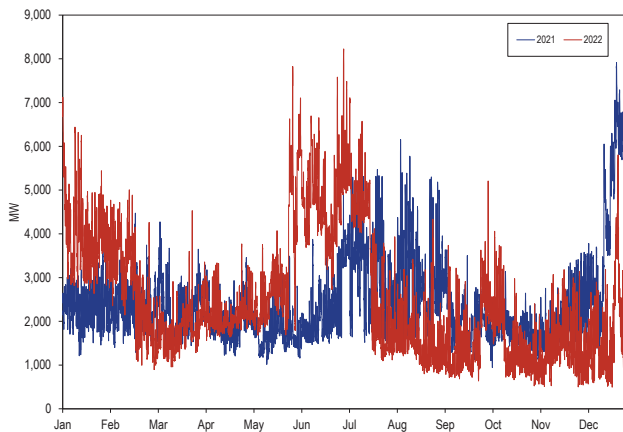
³⁸ See 151 FERC ¶ 61,208 at P 476 (2015).

³⁹ OA Schedule 1 § 1.10.1A(d).

⁴⁰ This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See PJM Filing, Attachment A (Redlines of OA Schedule 1 § 1.10.1A(d), EL15-29-000 (December 12, 2014). FERC rejected the proposed change. See 151 FERC ¶ 61,208 at P 476 (2015).

Figure 3-18 shows maximum emergency MW by hour in 2021 and 2022. The increase in maximum emergency MW in December 2021 through February 2022 and again in June 2022 was mainly due to coal availability, consumables inventory shortages and environmentally limited units. The increase in December 2022 was mainly caused by low oil inventories and environmentally limited oil fired units after some higher than normal operation on December 23 and 24, 2022.

Figure 3-18 Maximum Emergency MW by hour: 2021 and 2022



Parameter Limited Schedules

Cost-Based Offers

All resources in PJM are required to submit at least one cost-based offer. Cost-based offers, submitted by capacity resources for a defined set of technologies, are parameter limited based on unit specific parameter limits. Nuclear, wind, solar and hydro units are not subject to parameter limits.

Price-Based Offers

All capacity resources that choose to offer price-based offers are required to make available at least one price-based parameter limited offer (referred to as price-based PLS). For resources that are not capacity resources, the price-based parameter limited schedule is used by PJM for committing generation resources when a maximum emergency generation alert is declared. For capacity performance resources, the price-based parameter limited schedule is used by PJM for committing generation resources when hot weather alerts and cold weather alerts are declared.

The current implementation is not consistent with the goal of having parameter limited schedules, which is to prevent the use of inflexible operating parameters to exercise market power. Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the price-based parameter limited schedule during hot and cold weather alerts. Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the cost-based parameter limited schedule when a resource fails the TPS test. The Commission recognized this flaw in the implementation of market power mitigation in its order to show cause, issued June 17, 2021.⁴¹

PJM did not attempt to address this issue in 2021 or 2022. PJM has an opportunity to address the issue in the implementation of enhanced combined cycle modelling development. Implementing the MMU's recommendations would both solve the market power mitigation issues and decrease the day-ahead market solution time.⁴²

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 2022. The analysis includes units with technologies that are subject to parameter limits and offer both price-based and cost-based schedules.⁴³ Table 3-16 shows the number and percentage of day-ahead unit run hours that failed the TPS test but were committed on price schedules. Table 3-16 shows that 30.6 percent of unit hours for units that failed the 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.

⁴¹ See 175 FERC ¶ 61,231 (2021).

⁴² See "Offer Capping Issue Charge," MMU Presentation to the Market Implementation Committee (January 11, 2023), <http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Offer_Capping_and_Combined_Cycle_Modeling_Presentation_20230111.pdf>.

⁴³ Nuclear, wind, solar and hydro units are not subject to parameter limits.

Table 3-16 Parameter mitigation for units failing TPS test: 2022

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	28,640	30.6%
Committed on price schedule as flexible as cost	4,178	4.5%
Total committed on price schedule without parameter limits	32,818	35.1%
Committed on cost (cost capped)	58,538	62.5%
Committed on price PLS	2,257	2.4%
Total committed on PLS schedules (cost or price PLS)	60,795	64.9%

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market for units in zones where a cold weather alert or a hot weather alert or maximum generation emergency was declared in 2022. PJM declared cold weather alerts on 11 days and hot weather alerts on 31 days in 2022.⁴⁴ PJM also declared a Maximum Generation Emergency/Load Management Alert on December 23 through December 31, 2022, in addition to the cold weather alerts issued on December 23, 24, 25 and 26. The analysis includes units with technologies that are subject to parameter limits, with a CP commitment, in the zones where the cold or hot weather alerts were declared. Table 3-17 shows that 33.4 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.⁴⁵ 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 3-17 Parameter mitigation during weather alerts: 2022

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	74,703	33.4%
Committed on price schedule as flexible as PLS	22,384	10.0%
Total committed on price schedule without parameter limits	97,087	43.4%
Committed on cost (cost capped)	7,058	3.2%
Committed on price PLS	119,805	53.5%
Total committed on PLS schedules (cost or price PLS)	126,863	56.6%

Currently, there are no rules in the PJM tariff or manuals that limit the markup attributes of price-based PLS offers. The intent of the price-based PLS offer is to prevent the exercise of market power during high demand conditions by preventing units from offering inflexible operating parameters in order to extract higher market revenues or higher uplift payments. However, a generator can include a higher markup in the price-based PLS offer

than in the price-based non-PLS schedule. The result is that the offer is higher and market prices are higher as a result of the exercise of market power using the PLS offer. This defeats the purpose of requiring price-based PLS offers.

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

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

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

The MMU recommends, 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.

The MMU recommends, if the preferred recommendation is not implemented, that in order to ensure effective market power mitigation, PJM always enforce parameter

⁴⁴ 2022 State of the Market Report for PJM, Section 3: Energy Market, at Emergency Procedures.
⁴⁵ Nuclear, wind, solar and hydro units are not subject to parameter limits.

limited values when the TPS test is failed and during high load conditions such as cold and hot weather alerts and emergency conditions. PJM would separately mitigate the operating parameters and the financial parameters of the offers (incremental offer, startup cost, and no load cost).⁴⁶

Parameter Limits

Beginning June 1, 2020, all capacity resources, including resources in FRR capacity plans, are capacity performance resources. The unit specific parameter limits for capacity performance resources are based on default minimum operating parameter limits posted by PJM by technology type, and any adjustments based on a unit specific review process. These default parameters were based on analysis by the MMU.

The PJM tariff specifies that all generation capacity resources, regardless of the current commitment status, are subject to parameter limits on their cost-based offers. However, the tariff currently does not make it clear what parameter limit values are applicable for resources without a capacity commitment. The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance resources.

Unit Specific Adjustment Process

Market participants can request an adjustment to the default values of parameter limits for capacity performance resources by submitting supporting documentation which is reviewed by PJM and the MMU. The default minimum operating parameter limits or approved adjusted values are used by capacity performance resources 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.⁴⁷ Solar units, wind units, run of river hydro units, and nuclear units are currently not subject to parameter limits. The MMU analyzed, for the units that are subject to parameter limits, the proportion of units that use the default limits published by PJM and the proportion of units that have been provided unit specific adjustments for some of the parameters. Table 3-18 shows, for the delivery year beginning June 1, 2022, the number of units that submitted and had approved unit specific parameter limit adjustments, and the number of units that used the default parameter limits published by PJM.

Table 3-18 Adjusted unit specific parameter limit statistics: 2022/2023 Delivery Year

Technology Classification	Units Using Default Parameter Limits	Units with One or More Adjusted Parameter Limits	Percent of Units with One or More Adjusted Parameter Limits
Aero CT	120	37	23.6%
Frame CT	162	105	39.3%
Combined Cycle	89	31	25.8%
Reciprocating Internal Combustion Engines	66	4	5.7%
Solid Fuel NUG	34	6	15.0%
Oil and Gas Steam	9	13	59.1%
Subcritical Coal Steam	5	54	91.5%
Supercritical Coal Steam	1	36	97.3%
Pumped Storage	7	1	12.5%

⁴⁶ See "Comments of the Independent Market Monitor for PJM," Docket No. EL21-78 (October 15, 2021) at 18 - 19.

⁴⁷ 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>>.

Real-Time Values

The Commission rejected PJM's proposed revisions to add RTV rules to the tariff in an order issued on May 28, 2021. In its order, the Commission recognized that RTVs can be used to exercise market power by withholding generation and avoiding market power mitigation.⁴⁸

The real-time values submittal process was never defined in the PJM Operating Agreement. The process was defined only in PJM Manual 11. While there are a number of options for providing real-time unit status to PJM operators, PJM created a mechanism for the submission of such values called real-time values (RTVs). Unlike parameter exceptions, the use of real-time values made a unit ineligible for make whole payments, unless the market seller could justify such operation based on an actual constraint.⁴⁹ In the case of the notification time parameter, start time parameter, minimum run time and minimum down time parameters, a longer real-time value decreases the likelihood of the unit being committed, making the RTV a mechanism for exercising market power through withholding and for failing to meet the obligations of capacity resources.

PJM's proposed RTV mechanism was rejected by the Commission because it would weaken the existing market power mitigation rules including parameter limited schedules.⁵⁰

Beginning August 1, 2021, PJM provides guidance to market sellers that it will no longer accept real-time value submissions for economic reasons, such as due to choosing not to staff a unit. In its order to show cause issued on June 17, 2021, the Commission stated its concern that "the PJM Tariff appears to be unjust and unreasonable because it fails to contain provisions governing what happens if a seller is unable to meet its unit-specific parameters in real time".⁵¹ In its response to the Commission's order, PJM proposed tariff updates to allow generators to submit temporary exceptions during the operating day.⁵² These rules require market sellers to justify that the request is based on a physical and actual constraint by submitting supporting documentation within three business days, consistent with the existing

temporary parameter exception process. However, the September 15th Response proposes no consequences to market sellers who do not adhere to the proposed tariff defined rules on what is considered a valid justification for temporary exceptions.

Currently, a resource that is staffed or has remote start capability and offers according to its physical capability, and a resource that makes the economic choice not to staff or invest in remote start and economically or physically withholds to decrease the likelihood of commitment, are compensated identically in the capacity market. If a market seller makes an economic decision to not staff the unit or to not have remote start capability, and uses temporary parameter exceptions or RTVs to communicate the longer time to start to PJM, the unit's actual parameters are not recognized as inconsistent with its obligations as a capacity resource, not reflected in forced outages, and not reflected in eligibility for uplift payments. The market seller is able to withhold the unit in the energy market with no defined consequence, while other similarly situated units incur the costs associated with meeting their obligations. Such withholding is an exercise of market power. If market sellers instead represent that they are able to meet the time to start parameters, but the unit is not staffed or the unit is not equipped with remote start capability to meet its unit specific limits, there is no defined consequence for misrepresenting the unit's capability. In its September 15 Response, PJM proposes no explicit defined penalties for such behavior.

Units that override their turn down ratio (economic maximum divided by economic minimum) either use Real-Time Values or PJM's fixed gen flag, which functions identically to a real-time value.⁵³ These resources operate on their parameter limited schedules but override their output limit parameters with no consequence. The only difference between a Real-Time Value to override the turn down ratio parameter and the fixed gen flag is that the fixed gen resources receive uplift payments. These resources receive inefficient levels of uplift payments when they have market power. The September 15 Response does not address unstaffed units that refuse to meet their notification time or units

48 175 FERC ¶ 61,171 (2021).

49 See OA Schedule 1 § 3.2.3(e).

50 175 FERC ¶ 61,171 at P 36 (2021).

51 175 FERC ¶ 61,231 at P 17 (2021).

52 PJM. "Answer of PJM Interconnection LLC," Docket No. EL21-78 (September 15, 2021) ("September 15th Response").

53 PJM Markets Gateway User Guide, Section 6.9: Self-schedule a Generating Unit and Ignore PJM Dispatch Instruction at 41, <<https://www.pjm.com/~media/etools/markets-gateway/markets-gateway-user-guide.ashx>>.

that refuse to perform to their turn down ratio parameter by using fixed gen.

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

The better option, consistent with the no excuses approach of the capacity performance paradigm and consistent with long term incentives for flexibility, is to not pay any capacity resources an appropriate portion of the daily capacity value of the resource for days when it is not fully available consistent with its parameter limited schedule. If flexibility is valued as a generator attribute, the market design should not provide incentives to be inflexible. An effective market design should reward flexible operation, and ensure that Capacity Performance resources are paid for their capacity only when it meets their required level of flexibility. Without clearly defined consequences, market sellers will continue to submit inflexible parameters. The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits.⁵⁴

Generator Flexibility Incentives under Capacity Performance

In its June 9, 2015, order on capacity performance, the Commission determined that capacity performance resources should be able to reflect actual constraints based on not just the resource physical constraints, but also other constraints, such as contractual limits that are not based on the physical characteristics of the generator.⁵⁵ The Commission directed that

capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.⁵⁶ The Commission directed PJM to submit tariff language to establish a process through which capacity performance resources that operate outside the defined unit specific parameter limits can justify such operation and therefore remain eligible for make whole payments.⁵⁷

A primary goal of the capacity performance market design is to assign performance risk to generation owners and to ensure that capacity prices reflect underlying supply and demand conditions, including the cost of taking on performance risk. The June 9th Order's determination on parameters is not consistent with that goal. By permitting generation owners to establish unit parameters based on nonphysical limits, the June 9th Order weakened the incentives for units to be flexible and weakened the assignment of performance risk to generation owners. Contractual limits, unlike generating unit operational limits, are a function of the interests and incentives of the parties to the contracts. If a generation owner expects to be compensated through uplift payments for running for 24 hours regardless of whether the energy is economic or needed, that generation owner has no incentive to pay more to purchase the flexible gas service that would permit the unit to be flexible in response to dispatch.

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

The approach to parameters defined in the June 9th Order will increase energy market uplift payments substantially. While some uplift is necessary and

⁵⁴ 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>>.

⁵⁵ 151 FERC ¶ 61,208 at P 437 (2015) (June 9th Order).

⁵⁶ *Id.* at P 439.

⁵⁷ *Id.* at P 440.

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 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 recently, during hot weather conditions, a number of gas fired generators request temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters affected include notification time, minimum run time (MRT) and turn down ratio (TDR, the ratio of economic maximum MW to economic minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may, depending on the nature of the transportation service purchased, be forced to nominate an equal amount of gas for each hour in a 24 hour period, with penalties for deviating from the nominated quantity. This leads to requests for 24 hour minimum run times and turn down ratios close to 1.0, to avoid deviations from the hourly nominated quantity. Table 3-19 shows the number of units, and the installed capacity MW that submitted parameter exception requests for a 24 hour minimum run time due to gas pipeline restrictions. In 2022, there were 81 units in PJM with a total installed capacity of 10,019 MW that requested a 24 hour minimum run time on their parameter limited schedules based on pipeline restrictions.

Table 3-19 Units with 24 hour minimum run times due to gas pipeline restrictions: 2017 through 2022

Year	Number of Units With 24 Hour Minimum Run Time Exceptions	Installed Capacity (MW) With 24 Hour Minimum Run Time Exceptions
2017	20	3,216
2018	25	3,627
2019	37	5,616
2020	13	3,873
2021	61	7,513
2022	81	10,019

The increase in units requesting 24 hour minimum run times is a result of pipelines enforcing the pipeline tariff ratable take provisions. Pipelines have the authority to require ratable takes under their tariffs at any time although pipelines do not enforce ratable takes on a routine basis. Some generators have also requested extremely long notification times based on pipeline nomination deadlines. (See Table 3-66.) When pipelines enforce these deadlines, generators cannot obtain gas to flow for a given market hour once the deadline has passed for that hour and therefore they cannot start according to their normal notification plus start times (normally less than 30 minutes). For example, at 1700 EPT, the next nomination cycle is intraday 3 (ID3). The ID3 deadline is 2000 EPT for gas to flow starting at 2300 EPT. When these nomination deadlines are enforced, at 1700 EPT, a gas unit can only start at 2300 EPT (or in 6 hours). This effectively increases the time to start (notification time plus start time) from 30 minutes to 6 hours. The long notification times make the units unavailable for commitment in real time. Generators may request temporary exceptions based on pipeline restrictions in order to provide PJM with offers that accurately reflect their capabilities. Units operating inflexibly due to pipeline restrictions are eligible for uplift. Temporary exceptions should be limited to the duration of restrictions imposed by pipelines.

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

The MMU recommends that PJM 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.

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.⁵⁸ Up to congestion transactions may be submitted between any two buses on a list of 47 buses eligible for up to congestion transaction bidding.⁵⁹ Import and export transactions may be submitted at any interface pricing point, where an import is equivalent to a virtual offer that is injected into PJM and an export is equivalent to a virtual bid that is withdrawn from PJM.

Figure 3-19 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve of imports, the system aggregate supply curve without increment offers and imports, the system aggregate supply curve with increment offers, and the system aggregate supply curve with increment offers and imports for an example day in 2022.

Figure 3-19 Day-ahead aggregate supply curves: 2022 example day

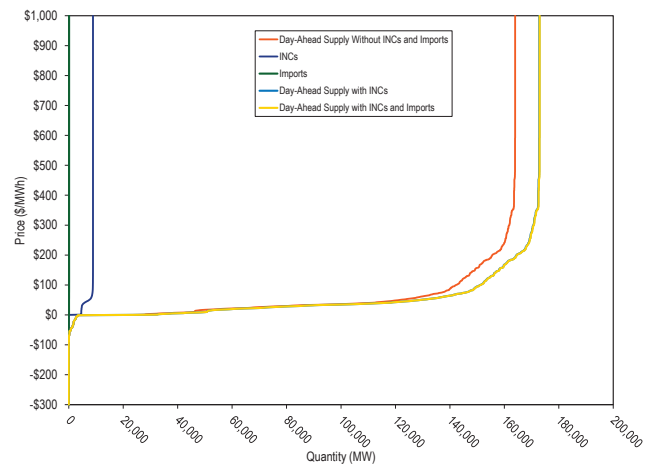


Table 3-20 shows the hourly average number of cleared and submitted increment offers and decrement bids by month in 2021 and 2022. The hourly average submitted increment offer MW increased by 37.3 percent and cleared increment MW increased by 55.2 percent in 2022 compared to 2021. The hourly average submitted

⁵⁸ 162 FERC ¶ 61,139 (2018).

⁵⁹ 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.xls) <<http://www.pjm.com/~media/etools/oasis/references/oasis-source-sink-link.xls>>.

decrement bid MW increased by 21.8 percent and cleared decrement MW increased by 21.3 percent in 2022 compared to 2021.

Table 3-20 Average hourly number of cleared and submitted INCs and DECs by month: January 2021 through December 2022

Year	Increment Offers				Decrement Bids				
	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	
2021	Jan	2,208	6,221	259	1,068	3,916	10,076	297	1,194
2021	Feb	2,078	5,476	264	972	5,123	11,556	280	1,303
2021	Mar	2,838	6,524	273	947	4,406	10,063	280	1,149
2021	Apr	3,053	6,998	297	974	3,569	9,188	223	928
2021	May	2,431	6,036	259	885	3,415	8,363	187	862
2021	Jun	1,898	5,290	180	726	4,971	10,854	197	1,024
2021	Jul	2,244	5,797	211	820	3,810	9,054	165	842
2021	Aug	1,788	4,944	202	816	4,016	9,483	182	1,032
2021	Sep	2,226	5,984	252	899	4,080	10,290	276	1,214
2021	Oct	1,993	5,465	294	956	4,079	10,372	308	1,315
2021	Nov	2,636	6,324	344	1,074	3,812	9,446	304	1,224
2021	Dec	2,344	5,813	271	895	5,354	11,290	369	1,191
2021	Annual	2,312	5,907	259	919	4,206	9,991	256	1,105
2022	Jan	2,898	7,135	308	1,069	6,513	14,228	375	1,559
2022	Feb	3,743	8,639	359	1,216	6,078	13,359	348	1,370
2022	Mar	4,072	9,403	337	1,143	5,579	12,511	256	1,074
2022	Apr	3,909	8,696	342	1,069	3,833	11,008	196	1,026
2022	May	3,588	8,381	319	1,029	4,960	12,441	247	1,072
2022	Jun	3,467	7,708	249	909	4,719	11,482	234	1,032
2022	Jul	3,060	7,249	266	1,068	4,451	10,703	192	976
2022	Aug	3,112	6,696	259	973	4,889	11,092	241	997
2022	Sep	3,352	7,280	257	1,109	6,157	11,806	287	1,003
2022	Oct	3,603	7,979	304	969	4,813	11,978	320	1,280
2022	Nov	4,586	9,985	373	1,268	4,504	12,304	307	1,229
2022	Dec	3,587	8,012	322	1,090	4,637	12,786	310	1,386
2022	Annual	3,578	8,089	308	1,075	5,089	12,137	276	1,167

Table 3-21 shows the average hourly number of up to congestion transactions and the average hourly MW by month in 2021 and 2022. The hourly average submitted up to congestion bid MW increased by 137.4 percent and cleared up to congestion bid MW increased by 87.8 percent in 2022 compared to 2021. The volume of bid and cleared up to congestion MW also increased during 2022, with November and December having the highest monthly totals.

Table 3-21 Average hourly cleared and submitted up to congestion bids by month: January 2021 through December 2022

		Up to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2021	Jan	7,277	20,412	546	1,062
2021	Feb	10,354	23,732	691	1,227
2021	Mar	8,776	24,571	548	1,087
2021	Apr	6,770	21,293	495	1,033
2021	May	6,976	20,674	585	1,164
2021	Jun	7,163	17,808	621	1,132
2021	Jul	6,743	16,386	572	1,041
2021	Aug	5,366	13,542	435	857
2021	Sep	6,659	16,579	471	1,138
2021	Oct	5,421	15,732	414	1,071
2021	Nov	6,761	18,741	490	1,106
2021	Dec	6,629	19,107	503	1,081
2021	Annual	7,050	19,014	530	1,082
2022	Jan	8,268	28,791	478	1,322
2022	Feb	11,908	31,383	632	1,452
2022	Mar	10,921	34,887	521	1,366
2022	Apr	9,030	37,400	440	1,342
2022	May	8,616	34,312	438	1,277
2022	Jun	10,213	31,573	520	1,305
2022	Jul	11,009	35,453	624	1,669
2022	Aug	15,007	48,449	756	2,143
2022	Sep	13,259	48,064	853	2,245
2022	Oct	14,738	53,955	739	2,237
2022	Nov	21,784	74,103	889	2,633
2022	Dec	24,019	82,190	1,000	2,797
2022	Annual	13,239	45,134	658	1,818

Table 3-22 shows the average hourly number of day-ahead import and export transactions and the average hourly MW from January 2021 through December 2022. In 2022, the average hourly submitted import transaction MW increased by 62.9 percent and the average hourly cleared import transaction MW increased by 75.6 percent compared to 2021. In 2022, the average hourly submitted export transaction MW increased by 9.9 percent and the average hourly cleared export transaction MW increased by 9.9 percent compared to 2021.

Table 3-22 Hourly average day-ahead number of cleared and submitted import and export transactions by month: January 2021 through December 2022

		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
2021	Jan	389	408	4	4	2,854	2,862	30	30
2021	Feb	267	285	3	4	4,581	4,658	41	42
2021	Mar	250	266	2	3	2,493	2,542	27	28
2021	Apr	214	249	3	3	2,364	2,376	24	24
2021	May	217	268	2	3	2,255	2,279	21	21
2021	Jun	155	177	2	2	3,463	3,489	30	30
2021	Jul	139	180	2	3	3,690	3,713	32	33
2021	Aug	116	158	2	3	3,619	3,641	31	31
2021	Sep	108	136	2	2	3,231	3,251	30	31
2021	Oct	103	133	2	3	2,478	2,513	24	25
2021	Nov	169	189	3	3	2,307	2,314	20	20
2021	Dec	118	135	2	2	4,033	4,055	32	33
2021	Annual	185	214	2	3	3,105	3,132	28	29
2022	Jan	295	322	4	5	4,349	4,360	35	36
2022	Feb	271	298	4	4	4,639	4,647	37	37
2022	Mar	169	196	3	3	3,822	3,842	27	27
2022	Apr	247	269	4	4	2,085	2,110	19	20
2022	May	428	441	5	5	2,521	2,566	21	21
2022	Jun	310	320	3	3	3,084	3,118	31	31
2022	Jul	268	283	3	3	3,217	3,265	31	31
2022	Aug	308	316	3	3	4,010	4,046	32	32
2022	Sep	356	396	2	3	3,830	3,870	29	30
2022	Oct	340	356	4	4	2,786	2,813	19	19
2022	Nov	419	455	4	5	2,819	2,813	24	24
2022	Dec	471	508	4	5	3,840	3,926	30	31
2022	Annual	325	349	4	4	3,412	3,443	28	28

Table 3-23 shows the frequency with which generation offers, import or export transactions, up to congestion transactions, decrement bids, increment offers and price-sensitive demand were marginal in January 2021 through December 2022. The marginal generation, DEC and INC MW in December were much lower and the marginal UTC MW were much higher compared to the rest of 2022 due to increased UTC activities in December.

Figure 3-21 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 2021 through December 2022, including the increase in up to congestion transactions in 2022.

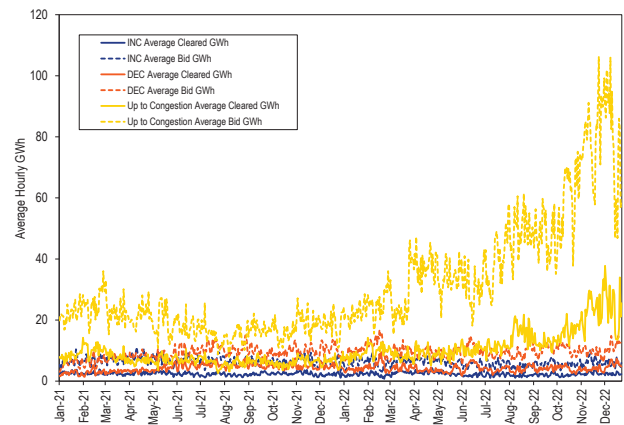
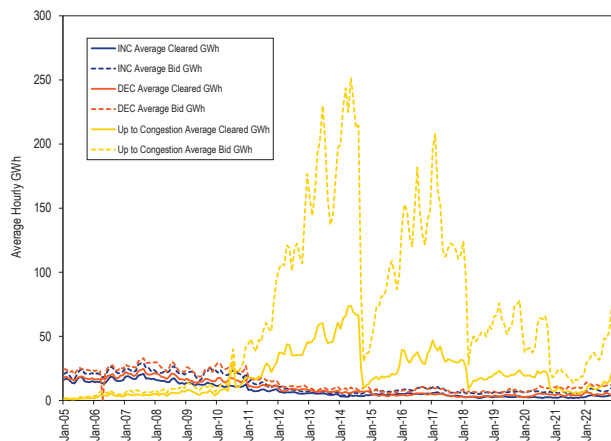
Table 3-23 Type of day-ahead marginal resources: January 2021 through December 2022

	2021						2022					
	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand
Jan	23.1%	0.1%	35.7%	24.2%	16.9%	0.0%	19.6%	0.1%	37.9%	26.0%	16.4%	0.0%
Feb	20.3%	0.4%	45.1%	23.1%	11.1%	0.0%	13.2%	0.1%	43.5%	23.8%	19.3%	0.0%
Mar	18.9%	0.1%	33.9%	26.5%	20.6%	0.0%	14.9%	0.1%	41.8%	18.9%	24.3%	0.0%
Apr	19.4%	0.2%	34.4%	21.6%	24.5%	0.0%	19.4%	0.3%	36.0%	17.6%	26.6%	0.0%
May	20.6%	0.2%	35.5%	24.5%	19.1%	0.0%	15.9%	0.4%	41.6%	21.6%	20.4%	0.0%
Jun	21.3%	0.2%	35.8%	30.4%	12.3%	0.0%	14.9%	0.2%	47.7%	22.2%	14.9%	0.0%
Jul	17.6%	0.3%	39.4%	28.8%	13.8%	0.0%	14.9%	0.3%	50.8%	19.9%	14.0%	0.0%
Aug	18.4%	0.5%	37.2%	30.5%	13.4%	0.0%	14.6%	0.2%	53.3%	17.9%	13.9%	0.0%
Sep	18.5%	0.5%	30.6%	29.5%	20.9%	0.0%	20.0%	0.5%	50.0%	16.3%	13.2%	0.0%
Oct	18.3%	0.4%	32.7%	30.0%	18.4%	0.0%	19.4%	0.3%	46.5%	17.4%	16.4%	0.0%
Nov	18.8%	0.2%	32.5%	26.9%	21.5%	0.0%	11.0%	0.5%	69.3%	10.9%	8.4%	0.0%
Dec	19.7%	0.2%	32.5%	29.6%	18.0%	0.0%	6.0%	0.5%	85.9%	5.5%	2.1%	0.0%
Annual	19.5%	0.3%	35.2%	27.1%	17.9%	0.0%	15.6%	0.3%	49.0%	18.8%	16.3%	0.0%

Figure 3-20 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month from 2005 through December 2022. The volume of submitted and cleared up to congestion bids returned to levels comparable to 2018 through October 2020, before uplift charges for up to congestion transactions took effect on November 1, 2020.

Figure 3-21 Daily bid and cleared INCs, DECs, and UTCs (GWh): January 2021 through December 2022

Figure 3-20 Monthly bid and cleared INCs, DECs and UTCs (GWh): January 2005 through December 2022



In order to evaluate the ownership of virtual bids, the MMU categorizes all participants making virtual bids in PJM as either physical or financial. Physical entities include utilities and customers that primarily take physical positions in PJM markets. Financial entities include banks and hedge funds that primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial

entities even if they are utilities in their own countries. Financial entities' share of submitted and cleared MWh of all types of virtual products increased in 2022 compared to 2021.

Table 3-24 shows, in 2021 and 2022, the total increment offers and decrement bids and cleared MW by type of parent organization.

Table 3-24 INC and DEC bids and cleared MWh by type of parent organization (MWh): 2021 and 2022

Category	2021				2022			
	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	126,426,159	90.8%	47,510,462	83.2%	163,530,478	92.3%	65,937,095	86.8%
Physical	12,834,962	9.2%	9,584,758	16.8%	13,646,768	7.7%	9,985,153	13.2%
Total	139,261,121	100.0%	57,095,220	100.0%	177,177,246	100.0%	75,922,249	100.0%

Table 3-25 shows, in 2021 and 2022, the total up to congestion bid and cleared MWh by type of parent organization. Up to congestion bids submitted by financial entities increased by 257 percent in 2022 compared 2021, from 149 million MWh to 383 million MWh, while up to congestion bids submitted by physical entities decreased during the same period. Financial entities submitted 96.8 percent of all up to congestion bids, up from 89.4 percent, and 93.8 percent of all cleared up to congestion bids, up from 85.7 percent, in 2022, compared to 2021.

Table 3-25 Up to congestion transactions by type of parent organization (MWh): 2021 and 2022

Category	2021				2022			
	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	148,844,114	89.4%	52,954,329	85.7%	382,847,894	96.8%	108,743,658	93.8%
Physical	17,716,432	10.6%	8,804,102	14.3%	12,521,864	3.2%	7,233,076	6.2%
Total	166,560,546	100.0%	61,758,431	100.0%	395,369,758	100.0%	115,976,734	100.0%

Table 3-26 shows, in 2021 and 2022, the total import and export transactions by whether the parent organization was financial or physical. The majority of import and export transactions in both day ahead and real time were submitted by physical entities in 2022.

Table 3-26 Import and export transactions by type of parent organization (MWh): 2021 and 2022

Category		2021		2022	
		Total Import and Export MWh	Percent	Total Import and Export MWh	Percent
Day-Ahead	Financial	11,112,618	38.8%	9,727,711	29.9%
	Physical	17,559,321	61.2%	22,794,422	70.1%
Total		28,671,939	100.0%	32,522,133	100.0%
Real-Time	Financial	15,123,148	28.7%	15,613,620	24.8%
	Physical	37,657,273	71.3%	47,430,896	75.2%
Total		52,780,421	100.0%	63,044,516	100.0%

Table 3-27 shows increment offers and decrement bids by the top 10 locations in 2021 and 2022. The top 10 INC and DEC locations in 2022 included five hubs, four interfaces, and one residual metered load aggregate.

Table 3-27 Virtual offers and bids by top 10 locations (MWh): 2021 and 2022

2021					2022				
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	142,870	7,171,196	7,314,066	WESTERN HUB	HUB	1,819,111	4,854,384	6,673,495
WESTERN HUB	HUB	986,937	2,038,390	3,025,327	MISO	INTERFACE	203,577	6,213,779	6,417,356
LINDENVFT	INTERFACE	52,287	1,839,732	1,892,019	SOUTH	INTERFACE	1,662,282	1,275,937	2,938,219
DOM_RESID_AGG	RESIDUAL METERED EDC	148,177	1,638,788	1,786,965	AEP-DAYTON HUB	HUB	697,652	1,872,234	2,569,886
BGE_RESID_AGG	RESIDUAL METERED EDC	209,818	1,171,638	1,381,456	LINDENVFT	INTERFACE	30,289	2,317,747	2,348,035
AEP-DAYTON HUB	HUB	336,156	1,031,997	1,368,153	N ILLINOIS HUB	HUB	1,313,192	1,012,737	2,325,929
NYIS	INTERFACE	646,968	695,336	1,342,305	DOM_RESID_AGG	RESIDUAL METERED EDC	121,670	2,134,820	2,256,491
N ILLINOIS HUB	HUB	454,626	666,150	1,120,776	NYIS	INTERFACE	862,920	1,239,608	2,102,528
AEPOHIO_RESID_AGG	RESIDUAL METERED EDC	163,078	853,661	1,016,739	NEW JERSEY HUB	HUB	1,082,433	869,337	1,951,770
SOUTH	INTERFACE	374,908	561,226	936,134	EASTERN HUB	HUB	747,557	998,069	1,745,627
Top ten total		3,515,824	17,668,116	21,183,940			8,540,682	22,788,653	31,329,335
PJM total		20,249,427	36,845,793	57,095,220			31,339,148	44,583,100	75,922,249
Top ten total as percent of PJM total		17.4%	48.0%	37.1%			27.3%	51.1%	41.3%

Table 3-28 shows up to congestion transactions for the top 10 source and sink pairs and associated source, sink and overall profits on each path in 2021 and 2022. Total profits for up to congestion transactions in 2022 were \$207.4 million, an increase of 935 percent compared to profits of \$22.2 million in 2021. The top 10 paths made up a larger share of profits in 2022, 33.1 percent, compared to 14.5 percent in 2021.⁶⁰ The UTCs from DOMINION HUB to DOM RESID AGG constituted 22 percent of all UTC profits 2022. Congestion in the Dominion Zone in 2022, especially in the summer months and continuing into the fall and winter, resulted from increased data center load in Northern Virginia. The increase in UTCs on this path alone, which made up 11 percent of all cleared UTC MW, was a major contributor to the overall increase in UTC volumes in 2022.

Table 3-28 Cleared up to congestion bids by top 10 source and sink pairs (MWh): 2021 and 2022⁶¹

2021							
Top 10 Paths by Cleared MWh							
Source	Source Type	Sink	Sink Type	Cleared MW	Source Revenue	Sink Revenue	UTC Profit
COMED_RESID_AGG	AGGREGATE	AEPIM_RESID_AGG	AGGREGATE	2,570,236	\$1,244,132	\$43,237	\$541,484
AEP GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	1,553,735	\$1,197,740	(\$50,913)	\$691,393
DOMINION HUB	HUB	DOM_RESID_AGG	AGGREGATE	1,211,566	(\$2,565,267)	\$3,003,939	(\$389,018)
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	1,192,820	\$792,942	(\$13,947)	\$334,542
MISO	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	1,099,374	\$1,609,490	(\$394,058)	\$839,784
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	1,019,303	(\$38,126)	\$721,284	\$204,002
CHICAGO GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	985,039	(\$816,890)	\$1,669,849	\$528,667
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	790,447	\$894,733	(\$485,537)	\$158,350
N ILLINOIS HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	701,779	\$525,047	(\$18,313)	\$297,868
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	693,387	\$134,423	\$182,197	\$8,368
Top ten total				11,817,687	\$2,978,224	\$4,657,739	\$3,215,440
PJM total				139,845,947	\$10,767,990	\$37,827,349	\$22,173,646
Top ten total as percent of PJM total				8.5%	27.7%	12.3%	14.5%
2022							
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	12,926,796	\$42,742,711	\$8,751,666	\$46,236,999
CHICAGO GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	2,995,417	\$3,775,251	(\$573,068)	\$2,073,552
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	2,570,180	\$5,120,731	(\$408,562)	\$3,747,000
AEP GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	2,005,313	(\$2,620,164)	\$7,443,234	\$3,646,674
MISO	INTERFACE	SOUTH	INTERFACE	1,949,377	\$5,229,203	(\$112,379)	\$3,917,559
CHICAGO GEN HUB	HUB	OHIO HUB	HUB	1,619,620	\$4,542,337	(\$1,641,757)	\$2,167,660
CHICAGO HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	1,539,827	\$2,190,750	(\$229,765)	\$1,343,681
APS_RESID_AGG	AGGREGATE	DOM_RESID_AGG	AGGREGATE	1,313,331	\$5,292,083	(\$304,286)	\$4,447,503
ATSI GEN HUB	HUB	OVEC_RESID_AGG	AGGREGATE	1,308,225	\$2,908,439	(\$1,526,051)	\$1,002,812
CHICAGO GEN HUB	HUB	CHICAGO HUB	HUB	1,240,584	\$686,538	(\$223,385)	\$275
Top ten total				29,468,670	\$69,867,879	\$11,175,648	\$68,583,716
PJM total				115,976,734	(\$43,691,734)	\$304,043,957	\$207,387,695
Top ten total as percent of PJM total				25.4%	(159.9%)	3.7%	33.1%

⁶⁰ 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.

⁶¹ The columns "Source Revenue" and "Sink Revenue" are totals before uplift charges are subtracted. The column "UTC Profit" includes uplift charges, in addition to the source and sink revenue, and so is less than the sum of the revenue from each side of the transaction.

Table 3-29 shows the average daily number of source-sink pairs that were offered and cleared each month from January 2021 through December 2022. The average number of submitted source-sink pairs per day increased from 1,368 source-sink pairs submitted in 2021 to 1,522 in 2022. The average number of cleared source-sink pairs per day increased from 1,200 in 2021 to 1,282 per day in 2022.

Table 3-29 Number of offered and cleared source and sink pairs: January 2021 through December 2022

Daily Number of Source-Sink Pairs					
Year	Month	Average		Average	
		Offered	Max Offered	Cleared	Max Cleared
2021	Jan	1,286	1,470	1,132	1,302
2021	Feb	1,303	1,514	1,210	1,449
2021	Mar	1,314	1,542	1,189	1,386
2021	Apr	1,309	1,559	1,146	1,388
2021	May	1,329	1,540	1,176	1,395
2021	Jun	1,291	1,412	1,161	1,289
2021	Jul	1,299	1,466	1,161	1,294
2021	Aug	1,403	1,622	1,221	1,469
2021	Sep	1,503	1,610	1,272	1,427
2021	Oct	1,461	1,567	1,212	1,349
2021	Nov	1,501	1,603	1,304	1,426
2021	Dec	1,421	1,582	1,216	1,345
2021	Annual	1,368	1,541	1,200	1,377
2022	Jan	1,398	1,555	1,228	1,405
2022	Feb	1,501	1,633	1,296	1,488
2022	Mar	1,392	1,609	1,178	1,449
2022	Apr	1,415	1,513	1,174	1,274
2022	May	1,417	1,525	1,181	1,291
2022	Jun	1,488	1,644	1,253	1,458
2022	Jul	1,551	1,703	1,305	1,478
2022	Aug	1,689	1,782	1,394	1,521
2022	Sep	1,686	1,855	1,436	1,646
2022	Oct	1,625	1,884	1,336	1,638
2022	Nov	1,552	1,754	1,301	1,497
2022	Dec	1,549	1,822	1,302	1,619
2022	Annual	1,522	1,690	1,282	1,480

Table 3-30 and Figure 3-22 show total cleared up to congestion transactions and the share of the top 10 up to congestion paths by transaction type (import, export, or internal) in 2021 and 2022. Total cleared up to congestion transactions increased by 87.8 percent from 61.8 million MWh in 2021 to 116.0 million MWh in 2022. Internal up to congestion transactions in 2022 were 79.8 percent of all up to congestion transactions, compared to 82.1 percent in 2021.

Table 3-30 Cleared up to congestion transactions and share of top 10 paths by type (MW): 2021 and 2022

	2021				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	2,645,482	2,857,649	654,212	11,404,877	17,562,220
PJM total (MW)	5,212,311	5,026,300	805,093	50,714,726	61,758,431
Top ten total as percent of PJM total	50.8%	56.9%	81.3%	22.5%	28.4%
PJM total as percent of all up to congestion transactions	8.4%	8.1%	1.3%	82.1%	100.0%
	2022				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	6,704,976	4,521,359	2,967,355	28,709,862	42,903,552
PJM total (MW)	10,613,012	9,624,643	3,155,745	92,583,334	115,976,734
Top ten total as percent of PJM total	63.2%	47.0%	94.0%	31.0%	37.0%
PJM total as percent of all up to congestion transactions	9.2%	8.3%	2.7%	79.8%	100.0%

Figure 3-22 shows the total volume of import, export, wheel, and internal up to congestion transactions by month from January 2005 through December 2022. 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.⁶² 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, 2018.⁶³ 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.⁶⁴ In 2022, the volume of cleared UTCs again increased, and by the end of the year was comparable to levels prior to the implementation of uplift charges.

Figure 3-22 Monthly cleared up to congestion transactions by type (GWh): January 2005 through December 2022

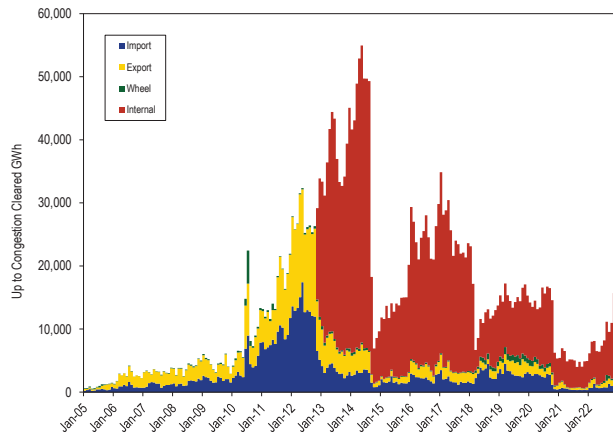


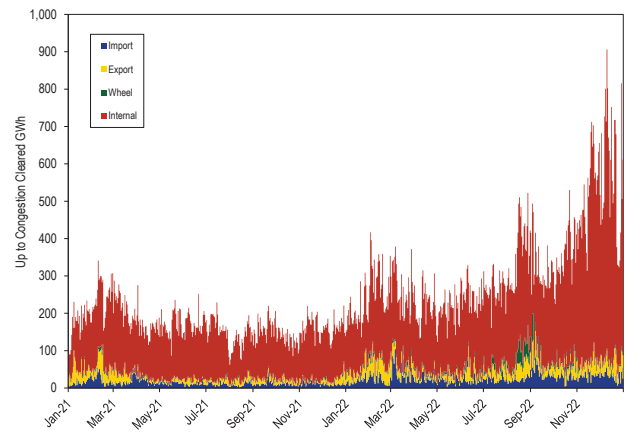
Figure 3-23 shows the daily cleared up to congestion GWh by transaction type from January 1, 2021, through December 31, 2022. In 2022, the total cleared GWh of import, export, and internal up to congestion transactions all increased compared to 2021.

⁶² See 162 FERC ¶ 61,139 (2018).

⁶³ *Id.*

⁶⁴ See 172 FERC ¶ 61,046 (2020).

Figure 3-23 Daily cleared up to congestion transaction by type (GWh): January 2021 through December 2022



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.⁶⁵

A key assumption underlying the February 2018 order is that the limited set of nodes available for virtual trading is sufficiently protected from false arbitrage trades because price spreads resulting from modeling differences between the day-ahead and real-time markets are mitigated by the averaging of prices over a large number of buses at aggregate nodes.⁶⁶ This assumption is not correct, given the large share of INC, DEC, and UTC profits still attributable to modeling or operational differences between day-ahead and real-time since the February 2018 order.

The assumption that modeling differences are averaged out over aggregate nodes does not hold for multiple

⁶⁵ 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."

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

nodes in the current list of available up to congestion bidding nodes. The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. For example, the MMU recommends eliminating UTC bidding at the following pricing points: DPLEASTON_RESID_AGG, PENNPOWER_RESID_AGG, UGI_RESID_AGG, SMECO_RESID_AGG, AEPKY_RESID_AGG, and VINELAND_RESID_AGG.

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

Market Performance

PJM locational marginal prices (LMPs) are a direct measure of market performance. The market performs optimally when the market structure provides incentives for market participants to behave competitively. In a competitive market, prices equal the short run marginal cost of the marginal unit of output and reflect the most efficient and least cost allocation of resources to meet demand.

LMP

The behavior of individual market entities within a market structure is reflected in market prices. PJM locational marginal prices (LMPs) are a direct measure of market performance. Price level is a good, general indicator of market performance, although overall price results must be interpreted carefully because of the

multiple factors that affect them. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of a closed loop interface related to demand side resources, surrogate constraints for reactive power and generator stability, or influence prices through manual interventions such as load biasing, changing constraint limits and penalty factors, and committing reserves beyond the requirement.

The real-time average LMP in 2022 increased 92.6 percent from 2021, from \$38.18 per MWh to \$75.53 per MWh. The real-time load-weighted average LMP in 2022 increased 101.4 percent from 2021, from \$39.78 per MWh to \$80.14 per MWh.

The real-time load-weighted average LMP in 2022 was 27.2 percent higher than the real-time fuel-cost adjusted load-weighted average LMP in 2022. If fuel and emission costs in 2022 had been the same as in 2021, holding everything else constant, the load-weighted LMP would have been lower, \$60.80 per MWh instead of the observed \$80.14 per MWh. The costs of fuel, emissions, and consumables, the fundamental components of the real-time load weighted average LMP, increased \$27.90 per MWh from \$27.36 per MWh in 2021 to \$55.26 per MWh in 2022, which accounts for 69.1 percent of the increase in real-time load-weighted average LMP.

The day-ahead average LMP in 2022 increased 87.4 percent from 2021, from \$37.76 per MWh to \$70.77 per MWh. The day-ahead load-weighted average LMP in 2022 increased 91.6 percent from 2021, from \$39.37 per MWh to \$75.44 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.⁶⁷ 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

67 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.

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.⁶⁸

LMP may, at times, be set by transmission penalty factors, which exceed \$1,000 per MWh. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, the transmission limits may be violated in the market dispatch solution. When this occurs, the shadow price of the constraint is set by transmission penalty factors. The shadow price directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing.

Fast Start Pricing

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

The pricing run calculates LMP using the same optimal power flow algorithm as the dispatch run while simultaneously relaxing the economic minimum and maximum output MW constraints for all eligible fast start units. Fast start units meet the following conditions: notification time plus start time are less than or equal to one hour; minimum run time is less than or equal to one hour; and units are online and running for PJM, not self-scheduled. This pricing method is intended to allow inflexible resources to set prices with their commitment costs per MWh added to their marginal costs.

DLMP and PLMP

Table 3-31 shows the day-ahead and real-time monthly load-weighted average DLMP and PLMP since September 2021. The real-time load-weighted average PLMP was \$80.14 per MWh for 2022, which is 5.0 percent, \$3.80 per MWh, higher than the real-time load-weighted average DLMP of \$76.34 per MWh. The day-ahead load-weighted average PLMP was \$75.44 per MWh for 2022, which is 0.1 percent, \$0.08 per MWh, higher than the day-ahead load-weighted average DLMP of \$75.35 per MWh. The highest monthly differences occurred in July and August 2022 when the real-time load-weighted average PLMP exceeded the DLMP by \$8.45 and \$8.06 per MWh.

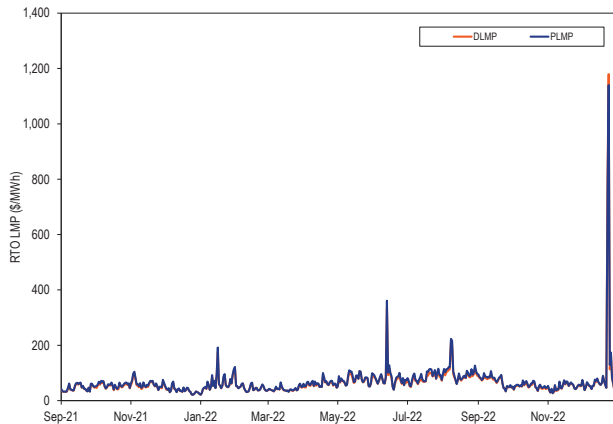
Table 3-31 Day-ahead and real-time load-weighted average DLMP and PLMP: September 2021 through December 2022

Year	Month	Day-Ahead Load-Weighted Average				Real-Time Load-Weighted Average			
		DLMP	PLMP	Difference	Percent Difference	DLMP	PLMP	Difference	Percent Difference
2021	Sep	\$46.00	\$46.14	\$0.13	0.3%	\$47.73	\$49.63	\$1.90	4.0%
2021	Oct	\$57.86	\$57.98	\$0.12	0.2%	\$54.53	\$58.42	\$3.89	7.1%
2021	Nov	\$60.76	\$61.00	\$0.24	0.4%	\$59.27	\$63.01	\$3.74	6.3%
2021	Dec	\$37.74	\$37.85	\$0.11	0.3%	\$37.37	\$38.92	\$1.55	4.2%
2021	Sep - Dec	\$50.30	\$50.46	\$0.15	0.3%	\$49.47	\$52.20	\$2.73	5.5%
2022	Jan	\$64.57	\$64.80	\$0.22	0.3%	\$66.43	\$69.06	\$2.64	4.0%
2022	Feb	\$49.96	\$50.35	\$0.39	0.8%	\$45.93	\$46.76	\$0.83	1.8%
2022	Mar	\$45.25	\$45.50	\$0.25	0.6%	\$41.83	\$43.56	\$1.73	4.1%
2022	Apr	\$64.10	\$64.18	\$0.08	0.1%	\$60.38	\$63.91	\$3.52	5.8%
2022	May	\$83.17	\$83.24	\$0.06	0.1%	\$79.04	\$83.16	\$4.12	5.2%
2022	Jun	\$90.24	\$90.54	\$0.29	0.3%	\$91.44	\$97.89	\$6.46	7.1%
2022	Jul	\$96.07	\$96.38	\$0.32	0.3%	\$84.03	\$92.48	\$8.45	10.1%
2022	Aug	\$106.18	\$106.07	(\$0.10)	(0.1%)	\$105.68	\$113.74	\$8.06	7.6%
2022	Sep	\$82.86	\$82.80	(\$0.06)	(0.1%)	\$74.08	\$78.29	\$4.22	5.7%
2022	Oct	\$58.30	\$58.37	\$0.07	0.1%	\$52.27	\$55.90	\$3.63	6.9%
2022	Nov	\$56.29	\$55.24	(\$1.05)	(1.9%)	\$50.86	\$52.93	\$2.07	4.1%
2022	Dec	\$93.02	\$93.39	\$0.37	0.4%	\$143.65	\$142.22	(\$1.42)	(1.0%)
2022	Jan - Dec	\$75.35	\$75.44	\$0.08	0.1%	\$76.34	\$80.14	\$3.80	5.0%

⁶⁸ 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).

Figure 3-24 shows the real-time daily average DLMP and PLMP since September 2021. As a result of Elliott, the real-time daily average DLMP was \$1,179.84 per MWh and PLMP was \$ 1,140.07 per MWh on December 24, 2022.

Figure 3-24 Real-time daily average DLMP and PLMP: September 2021 through 2022



Fast start pricing affected the difference between DLMP and PLMP in real time more than in day ahead. Figure 3-25 shows the hourly difference between DLMP and PLMP in day-ahead and real-time since September 2021.

As shown in Figure 3-25, the day-ahead market DLMP was \$92.58 per MWh higher than PLMP on August 24, 2022 1400 (EPT), and DLMP was \$575.44 per MWh higher than PLMP on November 7, 2022 1700 (EPT). The differences on these days are not due to fast start pricing. They occurred because PJM used a \$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 in the day-ahead market. As a result, generator offers clear the market based on high dispatch run LMPs but are settled based on lower pricing run LMPs, which is an inefficient market clearing result. There is no reason to use different transmission constraint penalty factors in the dispatch run and the pricing run and no reason has been provided.

In the real-time market, DLMP was \$1,048.40 per MWh higher than PLMP on December 23, 2022 1700 (EPT), and DLMP was \$1,176.00 per MWh higher than PLMP on December 24, 2022 0400 (EPT). PJM caps LMP in the pricing run at \$3,700 and does not cap LMP in the dispatch run. DLMP was \$362.02 per MWh lower than

PLMP on December 24, 2022 0100 (EPT), mainly due to high priced marginal fast start units.

Figure 3-25 Hourly difference between DLMP and PLMP for day-ahead and real-time: September 2021 through 2022

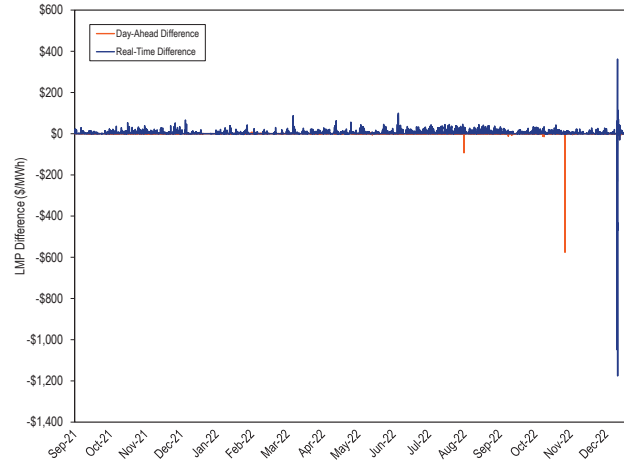


Figure 3-26 shows the hourly average load and LMP difference by hour of the day for 2022.

Figure 3-26 Hourly average load and LMP difference: 2022

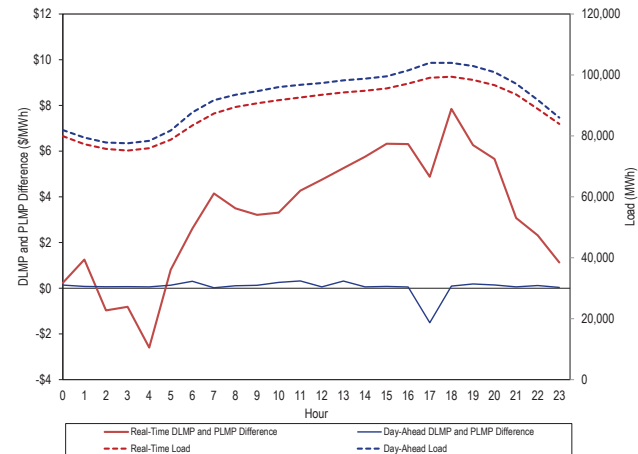


Table 3-32 shows the percent of total marginal units that are fast start units by unit type since September 2021. While wind units are defined as fast start units, a wind unit on the margin does not result in a higher PLMP than DLMP when the unit has no commitment costs.

Table 3-32 Fast start units as a percent of marginal units: September 2021 through 2022

Year	Month	Dispatch Run				Pricing Run			
		CT	Diesel	Wind	All Fast Start Units	CT	Diesel	Wind	All Fast Start Units
2021	Sep	1.3%	0.3%	0.2%	1.8%	4.9%	0.9%	0.2%	6.2%
2021	Oct	0.6%	0.2%	0.3%	1.1%	3.2%	0.5%	0.3%	4.0%
2021	Nov	0.5%	0.2%	0.4%	1.1%	3.4%	0.5%	0.4%	4.4%
2021	Dec	0.8%	0.1%	0.1%	1.2%	4.4%	0.3%	0.1%	5.0%
2021	Sep - Dec	0.8%	0.2%	0.3%	1.3%	4.0%	0.5%	0.2%	4.9%
2022	Jan	1.3%	0.3%	0.2%	1.8%	4.9%	0.9%	0.2%	6.2%
2022	Feb	0.6%	0.2%	0.3%	1.1%	3.2%	0.5%	0.3%	4.0%
2022	Mar	0.5%	0.2%	0.4%	1.1%	3.4%	0.5%	0.4%	4.4%
2022	Apr	0.8%	0.1%	0.1%	1.2%	4.4%	0.3%	0.1%	5.0%
2022	May	1.4%	0.7%	0.1%	2.4%	6.6%	1.2%	0.1%	8.1%
2022	Jun	2.3%	0.3%	0.1%	2.6%	9.3%	0.8%	0.1%	10.2%
2022	Jul	2.7%	0.6%	0.1%	3.3%	16.3%	1.4%	0.0%	17.7%
2022	Aug	2.0%	0.4%	0.0%	2.4%	12.0%	1.3%	0.0%	13.3%
2022	Sep	0.8%	0.3%	0.1%	1.2%	5.6%	1.0%	0.1%	6.7%
2022	Oct	2.2%	0.2%	0.3%	2.6%	6.6%	0.9%	0.2%	7.7%
2022	Nov	1.3%	0.2%	0.2%	1.7%	5.1%	0.9%	0.2%	6.1%
2022	Dec	1.2%	0.3%	0.0%	1.6%	6.3%	0.8%	0.0%	7.1%
2022	Jan - Dec	1.4%	0.3%	0.2%	1.9%	7.0%	0.9%	0.1%	8.0%

Table 3-33 shows the difference between day-ahead and real-time zonal average DLMP and PLMP for 2022. The average increase in real-time prices in BGE was \$4.12 per MWh, 5.1 percent, while the average increase in real-time prices in PECO was \$2.52 per MWh, 4.3 percent.

Table 3-33 Day-ahead and real-time zonal average DLMP and PLMP (Dollars per MWh): 2022

Zone	2022							
	Day-Ahead				Real-Time			
	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
ACEC	\$62.81	\$62.97	\$0.16	0.3%	\$63.13	\$65.76	\$2.63	4.2%
AEP	\$69.95	\$70.09	\$0.15	0.2%	\$68.74	\$72.02	\$3.28	4.8%
APS	\$70.97	\$71.19	\$0.22	0.3%	\$69.54	\$72.98	\$3.44	4.9%
ATSI	\$69.27	\$69.44	\$0.18	0.3%	\$67.21	\$70.45	\$3.23	4.8%
BGE	\$81.65	\$81.83	\$0.18	0.2%	\$80.53	\$84.65	\$4.12	5.1%
COMED	\$60.26	\$60.39	\$0.13	0.2%	\$57.97	\$60.90	\$2.94	5.1%
DAY	\$72.43	\$72.59	\$0.16	0.2%	\$70.83	\$74.22	\$3.40	4.8%
DUKE	\$71.12	\$71.27	\$0.15	0.2%	\$69.28	\$72.62	\$3.34	4.8%
DOM	\$84.12	\$83.56	(\$0.56)	(0.7%)	\$85.78	\$89.37	\$3.59	4.2%
DPL	\$67.25	\$67.43	\$0.18	0.3%	\$67.95	\$71.57	\$3.62	5.3%
DUO	\$68.01	\$68.18	\$0.18	0.3%	\$66.31	\$69.51	\$3.20	4.8%
EKPC	\$70.30	\$70.44	\$0.14	0.2%	\$69.60	\$72.89	\$3.29	4.7%
JCPLC	\$64.02	\$64.19	\$0.17	0.3%	\$64.51	\$67.30	\$2.80	4.3%
MEC	\$73.12	\$73.27	\$0.15	0.2%	\$71.84	\$75.09	\$3.25	4.5%
OVEC	\$68.49	\$68.64	\$0.15	0.2%	\$66.99	\$70.18	\$3.20	4.8%
PECO	\$61.64	\$61.80	\$0.16	0.3%	\$61.91	\$64.43	\$2.52	4.1%
PE	\$68.50	\$68.68	\$0.19	0.3%	\$66.55	\$69.62	\$3.08	4.6%
PEPCO	\$78.90	\$79.07	\$0.17	0.2%	\$77.90	\$81.80	\$3.90	5.0%
PPL	\$67.50	\$67.66	\$0.16	0.2%	\$66.74	\$69.69	\$2.95	4.4%
PSEG	\$64.82	\$64.99	\$0.17	0.3%	\$65.44	\$68.27	\$2.83	4.3%
REC	\$67.13	\$67.29	\$0.17	0.2%	\$67.16	\$70.15	\$2.99	4.4%

Table 3-34 shows the difference between day-ahead and real-time average DLMP and PLMP for PJM hubs for 2022.

Table 3-34 Day-ahead and real-time average DLMP and PLMP for PJM hubs (Dollars per MWh): 2022

Hub	2022							
	Day-Ahead				Real-Time			
	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
AEP GEN HUB	\$67.92	\$68.08	\$0.16	0.2%	\$66.11	\$69.25	\$3.14	4.7%
AEP-DAYTON HUB	\$69.26	\$69.41	\$0.15	0.2%	\$67.45	\$70.68	\$3.23	4.8%
ATSI GEN HUB	\$67.90	\$68.07	\$0.18	0.3%	\$65.60	\$68.74	\$3.14	4.8%
CHICAGO GEN HUB	\$59.32	\$59.45	\$0.13	0.2%	\$56.89	\$59.80	\$2.90	5.1%
CHICAGO HUB	\$60.52	\$60.65	\$0.13	0.2%	\$58.19	\$61.15	\$2.96	5.1%
DOMINION HUB	\$76.47	\$76.50	\$0.03	0.0%	\$76.04	\$79.56	\$3.52	4.6%
EASTERN HUB	\$67.31	\$67.50	\$0.18	0.3%	\$67.29	\$70.80	\$3.51	5.2%
N ILLINOIS HUB	\$60.03	\$60.17	\$0.13	0.2%	\$57.79	\$60.71	\$2.92	5.1%
NEW JERSEY HUB	\$64.15	\$64.31	\$0.17	0.3%	\$64.64	\$67.42	\$2.78	4.3%
OHIO HUB	\$69.14	\$69.30	\$0.15	0.2%	\$67.28	\$70.51	\$3.23	4.8%
WEST INT HUB	\$71.04	\$71.13	\$0.09	0.1%	\$69.37	\$72.66	\$3.29	4.7%
WESTERN HUB	\$72.90	\$73.09	\$0.18	0.3%	\$70.82	\$74.25	\$3.43	4.8%

Table 3-35 shows the frequency of the real-time pricing interval differences in DLMP and PLMP by price range for PJM zones for 2022.

Table 3-35 Real-time interval difference (dollars per MWh) between zonal DLMP and PLMP for 2022

Zone	2022									
	(< \$50)	(\$50 to \$100)	(\$100 to \$200)	(\$200 to \$500)	(\$500 to \$1000)	(\$1000 to \$2000)	(\$2000 to \$5000)	(\$5000 to \$10000)	(\$10000 to \$20000)	(>= \$20000)
PJM-RTO	0.1%	0.0%	0.6%	48.0%	39.7%	6.7%	4.3%	0.5%	0.1%	0.0%
ACEC	0.1%	0.2%	6.7%	48.3%	35.5%	4.9%	3.6%	0.6%	0.1%	0.0%
AEP	0.1%	0.0%	0.8%	48.1%	39.4%	6.8%	4.3%	0.5%	0.1%	0.0%
APS	0.1%	0.0%	0.6%	48.1%	39.2%	6.9%	4.4%	0.5%	0.2%	0.0%
ATSI	0.0%	0.0%	0.8%	48.0%	39.8%	6.6%	4.2%	0.5%	0.1%	0.0%
BGE	0.1%	0.1%	2.6%	48.0%	35.5%	7.1%	5.4%	1.1%	0.2%	0.0%
COMED	0.0%	0.1%	1.9%	48.3%	39.0%	6.2%	3.9%	0.4%	0.1%	0.0%
DAY	0.0%	0.0%	0.7%	48.1%	39.1%	6.9%	4.5%	0.5%	0.1%	0.0%
DUKE	0.1%	0.0%	0.9%	48.1%	39.0%	7.0%	4.3%	0.5%	0.1%	0.0%
DOM	0.1%	0.3%	1.9%	48.1%	36.9%	6.7%	4.9%	0.8%	0.1%	0.0%
DPL	0.1%	0.3%	10.8%	48.2%	30.6%	4.6%	3.4%	1.4%	0.5%	0.0%
DUQ	0.0%	0.0%	0.8%	48.1%	39.8%	6.5%	4.1%	0.5%	0.1%	0.0%
EKPC	0.0%	0.0%	0.9%	48.1%	39.2%	6.9%	4.3%	0.5%	0.1%	0.0%
JCPLC	0.1%	0.1%	3.3%	48.2%	38.9%	5.1%	3.7%	0.6%	0.1%	0.0%
MEC	0.1%	0.3%	2.0%	48.0%	38.7%	6.1%	4.0%	0.8%	0.1%	0.0%
OVEC	0.1%	0.0%	1.0%	48.1%	39.4%	6.8%	4.1%	0.5%	0.1%	0.0%
PECO	0.1%	0.2%	9.6%	48.2%	32.8%	4.9%	3.5%	0.6%	0.1%	0.0%
PE	0.1%	0.1%	0.7%	47.9%	40.2%	6.6%	3.9%	0.4%	0.0%	0.0%
PEPCO	0.1%	0.1%	2.3%	48.0%	36.3%	7.0%	5.1%	0.9%	0.1%	0.0%
PPL	0.1%	0.1%	2.0%	48.0%	39.7%	5.8%	3.7%	0.6%	0.1%	0.0%
PSEG	0.1%	0.1%	2.9%	48.2%	39.0%	5.2%	3.8%	0.6%	0.1%	0.0%
REC	0.1%	0.1%	1.7%	48.1%	40.0%	5.5%	3.9%	0.6%	0.1%	0.0%

Real-Time Average LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.⁶⁹

PJM Real-Time Average LMP

Table 3-36 shows the real-time average LMP in 1998 through 2022.⁷⁰ The real-time average LMP in 2022 increased \$35.35 per MWh, or 92.6 percent from 2021, from \$38.18 per MWh to \$75.53 per MWh. This is the highest real-time average LMP and the largest year over year increase in the real-time average LMP since the start of the PJM markets in 1999.

Table 3-36 Real-time average LMP (Dollars per MWh): 1998 through 2022

	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%

PJM Real-Time Average LMP Duration

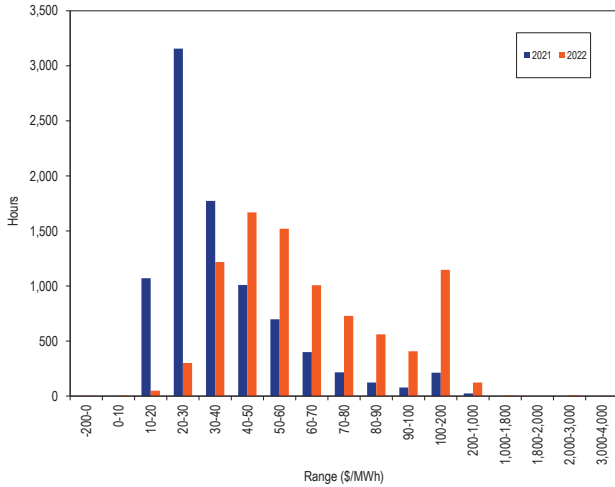
Figure 3-27 shows the hourly distribution of the real-time average LMP in 2021 and 2022. In 2021, the mostly common price range was \$20 to \$30 per MWh. In 2022, the mostly common price range was \$40 to \$50 per MWh. There were 8,524 hours in 2021, and 7,471 hours in 2022 with an average LMP below \$100 per MWh.

There were 19 hours with an average LMP above \$1,000 per MWh in 2022, including three hours with an average LMP above \$3,000 per MWh on December 23 and 24, 2022.

69 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>.

70 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.

Figure 3-27 Distribution of real-time LMP: 2021 and 2022



Real-Time Load-Weighted Average LMP

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

PJM Real-Time Load-Weighted Average LMP

Table 3-37 shows the real-time load-weighted average LMP in 1998 through 2022. The real-time load-weighted average LMP in 2022 increased \$40.36 per MWh, or 101.4 percent from 2021, from \$39.78 per MWh to \$80.14 per MWh. This is the highest real-time load-weighted average LMP since 1998.

Table 3-37 Real-time load-weighted average LMP (Dollars per MWh): 1998 through 2022

	Real-Time Load-Weighted Average LMP			Year to Year Change			
	Average	Median	Standard Deviation	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%

PJM Real-Time Monthly Load-Weighted Average LMP

Figure 3-28 shows the real-time monthly and yearly load-weighted average LMP for 1999 through 2022.

Figure 3-28 Real-time monthly and yearly load-weighted average LMP: 1999 through 2022

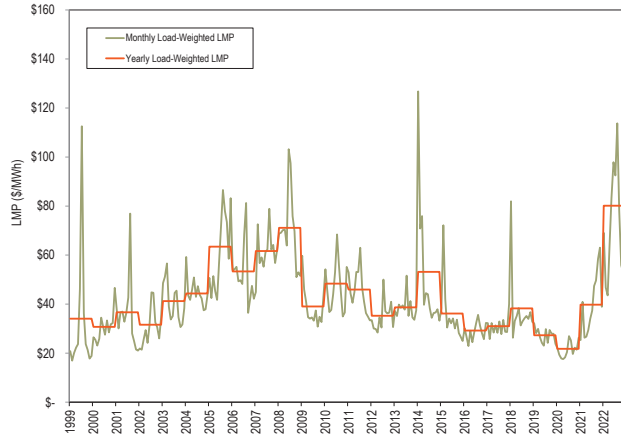


Table 3-38 shows the real-time monthly on peak and off peak load-weighted average LMP in 2021 and 2022. The off peak value was higher than the on peak value in January and December 2022 as a result of weather related demand during off peak hours.

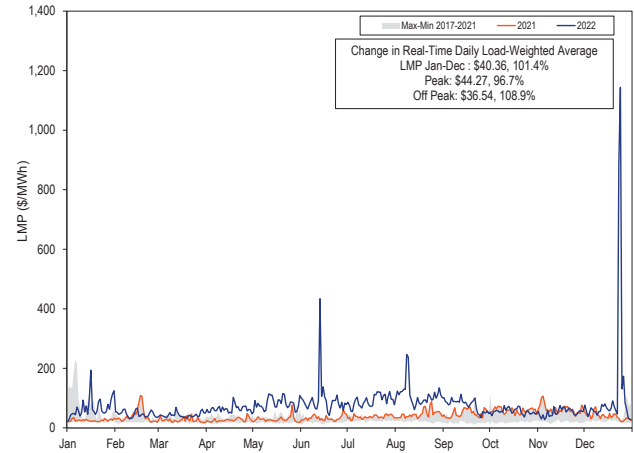
Table 3-38 Real-time monthly on peak and off peak load-weighted average LMP (Dollars per MWh): 2021 through 2022

	2021				2022			
	Off Peak	On Peak	Difference	Percent Difference	Off Peak	On Peak	Difference	Percent Difference
Jan	\$23.53	\$27.45	\$3.91	16.6%	\$74.99	\$62.54	(\$12.46)	(16.6%)
Feb	\$35.40	\$46.40	\$11.01	31.1%	\$45.70	\$47.86	\$2.16	4.7%
Mar	\$23.98	\$28.43	\$4.45	18.6%	\$41.58	\$45.41	\$3.83	9.2%
Apr	\$22.60	\$30.45	\$7.86	34.8%	\$55.93	\$71.89	\$15.96	28.5%
May	\$22.58	\$36.80	\$14.23	63.0%	\$66.12	\$100.85	\$34.73	52.5%
Jun	\$27.50	\$39.88	\$12.38	45.0%	\$61.63	\$126.83	\$65.20	105.8%
Jul	\$31.52	\$42.83	\$11.31	35.9%	\$71.83	\$114.13	\$42.31	58.9%
Aug	\$36.74	\$56.71	\$19.97	54.4%	\$85.89	\$136.31	\$50.42	58.7%
Sep	\$39.47	\$59.03	\$19.56	49.6%	\$66.36	\$89.76	\$23.40	35.3%
Oct	\$49.53	\$67.34	\$17.81	36.0%	\$47.61	\$64.50	\$16.90	35.5%
Nov	\$55.73	\$70.49	\$14.76	26.5%	\$45.48	\$60.50	\$15.01	33.0%
Dec	\$34.83	\$42.56	\$7.73	22.2%	\$153.54	\$129.51	(\$24.03)	(15.7%)

PJM Real-Time Daily Load-Weighted Average LMP

Figure 3-29 shows the real-time daily load-weighted average LMP in 2021 through 2022.

Figure 3-29 Real-time daily load-weighted average LMP: 2021 through 2022



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

Figure 3-30 shows the PJM real-time monthly load-weighted average LMP and inflation adjusted monthly load-weighted average LMP from January 1998 through December 2022.⁷¹ Table 3-39 shows the PJM real-time load-weighted average LMP and inflation adjusted load-weighted average LMP for every year from 1998 through 2022. The nominal yearly PJM real-time load-weighted average LMP for 2022 was the highest since the PJM Real-Time Energy Market was implemented in 1999. The inflation adjusted yearly PJM real-time load-weighted average LMP for 2022 was the fourth highest since 1999.

Figure 3-30 Real-time monthly load-weighted average LMP unadjusted and adjusted for inflation: January 1998 through December 2022

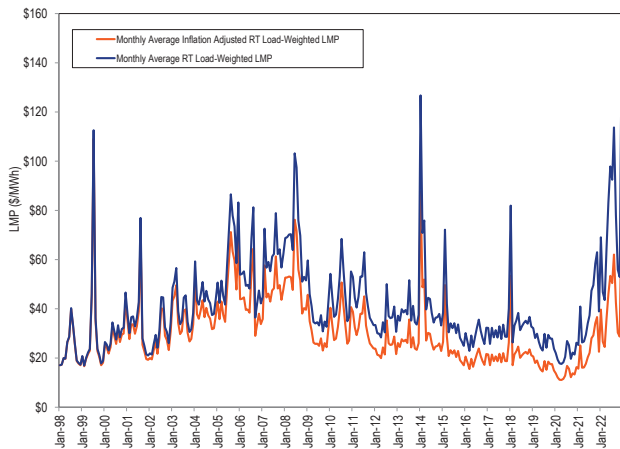


Table 3-39 Real-time load-weighted and inflation adjusted load-weighted average LMP: 1998 through 2022

	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

Real-Time Dispatch and Pricing

In the first ten months of 2021, real-time dispatch and pricing continued to not be temporally aligned. 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).⁷² The final real-time LMPs and ancillary service clearing prices are determined for every five minute interval by LPC.

Real-Time SCED and LPC

LPC uses data from an approved RT SCED solution that was used to dispatch the resources in the system. RT SCED solves to meet load and reserve requirements forecast at a future point in time, called the target time. Prior to 2021, on average, PJM operators approved more than one RT SCED solution per five minute target time to

⁷¹ 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 12, 2023)

⁷² See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 122 (Oct. 1, 2022)

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

Table 3-40 shows the number of RT SCED case solutions, the number of solutions that were approved and the number and percent of approved solutions used in LPC. Until February 24, 2020, RT SCED was automatically executed every three minutes with operators having the ability to execute additional cases in between the automatically executed cases. Beginning February 24, 2020, PJM changed the RT SCED automatic execution frequency to once every four minutes. On June 22, 2020, PJM changed the RT SCED execution frequency to once every five minutes. PJM operators continue to have the ability to execute additional RT SCED cases. Prior to June 3, 2021, each execution of RT SCED produced three solutions, using three different levels of load bias. Beginning June 3, 2021, each execution of RT SCED produces five solutions, using five different levels of load bias. Since prices are calculated every five

minutes while five SCED solutions are produced every five minutes, there is, by definition, a larger number of SCED solutions than there are five minute intervals in any given period.

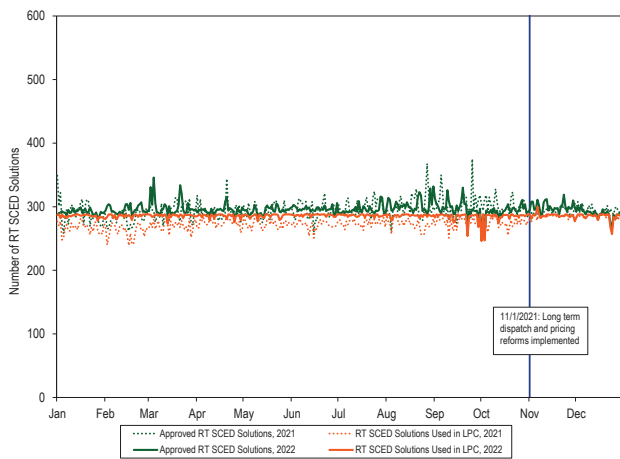
Table 3-40 shows that in 2022, 96.5 percent of approved RT SCED solutions that were used to send dispatch signals to generators were used in calculating real-time energy market prices, compared to 92.8 percent in 2021. The percent of approved solutions used for pricing increased in 2020 with the decrease in the frequency of executed RT SCED cases.

Figure 3-31 shows the daily number of RT SCED cases approved by PJM operators to send dispatch signals to resources, and the subset of approved RT SCED cases that were used in LPC to calculate LMPs in 2021 and 2022, and the date when PJM implemented the new real-time dispatch process that aligned the dispatch, pricing and settlement intervals. Figure 3-31 shows that the five minute dispatch reforms implemented on November 1, 2021 improved the percentage of dispatch signals reflected in prices.

Table 3-40 RT SCED cases solved, approved and used in pricing: 2021 and 2022

Month	2021				2022			
	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	31,395	9,022	8,276	91.7%	46,494	9,035	8,846	97.9%
Feb	30,489	7,888	7,308	92.6%	41,456	8,281	8,001	96.6%
Mar	32,456	9,069	8,372	92.3%	45,704	9,296	8,863	95.3%
Apr	29,586	8,798	8,220	93.4%	44,155	8,832	8,566	97.0%
May	30,438	9,124	8,468	92.8%	45,385	9,118	8,862	97.2%
Jun	46,184	8,847	8,133	91.9%	43,995	8,900	8,605	96.7%
Jul	47,792	9,291	8,513	91.6%	45,453	9,151	8,879	97.0%
Aug	47,580	9,326	8,459	90.7%	45,161	9,395	8,869	94.4%
Sep	46,899	9,088	8,270	91.0%	43,623	8,956	8,523	95.2%
Oct	46,707	9,333	8,538	91.5%	45,384	9,041	8,779	97.1%
Nov	44,316	8,778	8,539	97.3%	44,080	9,000	8,594	95.5%
Dec	45,770	9,114	8,852	97.1%	45,334	8,967	8,822	98.4%
Total	479,612	107,678	99,948	92.8%	536,224	107,972	104,209	96.5%

Figure 3-31 Daily RT SCED solutions approved for dispatch signals and solutions used in pricing: 2021 and 2022



PJM’s process for solving and approving RT SCED cases, and selecting approved RT SCED cases to use in LPC to calculate LMPs had inconsistencies that lead to downstream impacts for energy and reserve dispatch and settlements. 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. In 2021, the frequency of automatic execution of RT SCED cases was one every five minutes. 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 overrode 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.⁷³ 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.

⁷³ See Docket No. ER19-2573-000.

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.

Table 3-41 shows the average duration of the period when dispatch instructions corresponded to the prevailing prices in 2020, 2021 and 2022. Prior to October 15, 2020, PJM used the latest approved RT SCED solution available at the time of LPC execution, regardless of the SCED target time, to calculate prices for the current five minute pricing interval. The average duration of correspondence ranged from 3 minutes 11 seconds to 3 minutes 37 seconds from January through October 15, 2020, varying with changes to the frequency of automatic RT SCED execution. The percent of time that prices were consistent with the dispatch instructions was 67.2 to 69.9 percent, on average. This was far from the goal of 100 percent correspondence between five minute dispatch instructions and prices. With the short term changes to RT SCED that were implemented on October 15, 2020, the prices no longer corresponded to the dispatch instructions. Table 3-41 shows that during the first 10 months of 2021, the dispatch instructions were consistent with prevailing prices for only 33 seconds. During this period, the percent of time that prices were consistent with the

dispatch instructions was 9.0 percent. This is because by the time LMPs reflected the dispatch signals from an approved RT SCED solution, dispatchers had approved a new solution, and resources were instructed to follow new dispatch signals that did not align with the LMPs used to settle the current five minute interval. In other words, prices consistently lagged dispatch instructions by five minutes, except in cases where dispatchers had not approved a new SCED solution five minutes after a previously approved solution. 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. With these changes implemented on November 1, the dispatch instructions were consistent with the prices on average for 4 minutes and 46 seconds out of each five minute interval, or 95.4 percent of each five minute interval during November and December, 2021. 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.

Table 3-41 Dispatch instructions reflected in prices: 2020 through 2022

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%

For correct price signals and compensation, energy (LMP) and ancillary service pricing should align with the dispatch solution that is the basis for those prices and with the actual physical dispatch period during which that dispatch solution is realized for each and every real-time market interval.⁷⁴ This only happens when RT SCED and LPC both use a five minute ramp time, consistent with the five minute real-time settlement period in PJM. The MMU recommended that PJM approve one RT SCED case for each five minute interval to dispatch resources during that interval using a five minute ramp time, and that PJM calculate prices using LPC for that five minute

⁷⁴ See *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 155 FERC ¶ 61,276 (2016).

interval using the same approved RT SCED case. PJM adopted the recommended changes on November 1, 2021. This resulted in prices used to settle energy for the five minute interval that ends at the RT SCED dispatch target time calculated consistent with the economic dispatch that targets the end of that five minute interval.⁷⁵

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.⁷⁶ Table 3-42 shows the number of five minute intervals in each month and number of five minute intervals in each month for which PJM recalculated real-time prices in 2021 and 2022. In 2022, PJM recalculated LMPs for 3,635 five minute intervals or 3.46 percent of the total 105,120 five minute intervals.

Table 3-42 Number of five minute interval real-time prices recalculated: January 2021 through December 2022

Month	2021		2022	
	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	12	8,928	179
February	8,064	496	8,064	663
March	8,916	49	8,916	361
April	8,640	266	8,640	345
May	8,928	29	8,928	188
June	8,640	22	8,640	170
July	8,928	190	8,928	218
August	8,928	58	8,928	339
September	8,640	31	8,640	343
October	8,928	22	8,928	364
November	8,652	162	8,652	254
December	8,928	165	8,928	211
Total	105,120	1,502	105,120	3,635

Day-Ahead Average LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.⁷⁷

PJM Day-Ahead Average LMP

Table 3-43 shows the day-ahead average LMP in 2001 through 2022. The day-ahead average LMP in 2022 increased \$33.01 per MWh, or 87.4 percent from 2021, from \$37.76 per MWh to \$70.77 per MWh. This is the highest day-ahead average LMP and the largest year over year increase in the day-ahead average LMP since the first full year of the PJM day-ahead energy market in 2001.

⁷⁵ The implementation of fast start pricing on September 1, 2021, resulted in a much more significant misalignment between price and dispatch signals.

⁷⁶ OA Schedule 1 § 1.10.8(e).

⁷⁷ 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>.

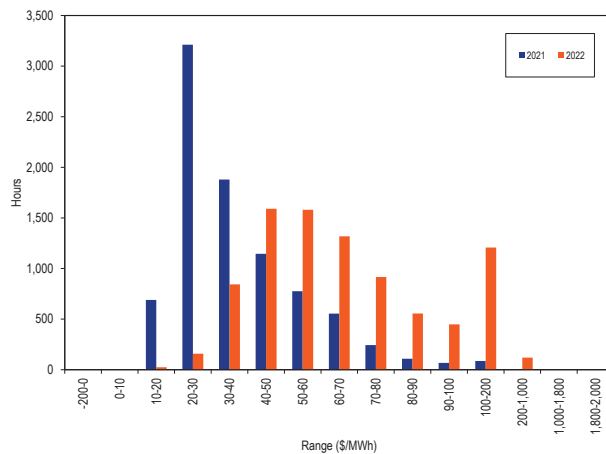
Table 3-43 Day-ahead average LMP (Dollars per MWh): 2001 through 2022

	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%

PJM Day-Ahead Average LMP Duration

Figure 3-32 shows the hourly distribution of the day-ahead average LMP in 2021 and 2022.

Figure 3-32 Distribution of day-ahead LMP: 2021 and 2022



Day-Ahead Load-Weighted Average LMP

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

PJM Day-Ahead Load-Weighted Average LMP

Table 3-44 shows the day-ahead load-weighted average LMP in 2001 through 2022. The day-ahead load-weighted average LMP in 2022 increased \$36.07, or 91.6 percent from 2021, from \$39.37 per MWh to \$75.44 per MWh. This is the highest day-ahead load-weighted average LMP and the largest year over year increase in day-ahead load-weighted average LMP since the first full year of the PJM day-ahead energy market in 2001.

Table 3-44 Day-ahead load-weighted average LMP (Dollars per MWh): 2001 and 2022

	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%

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 2022.

Figure 3-33 Day-ahead monthly and yearly load-weighted average LMP: 2001 through 2022

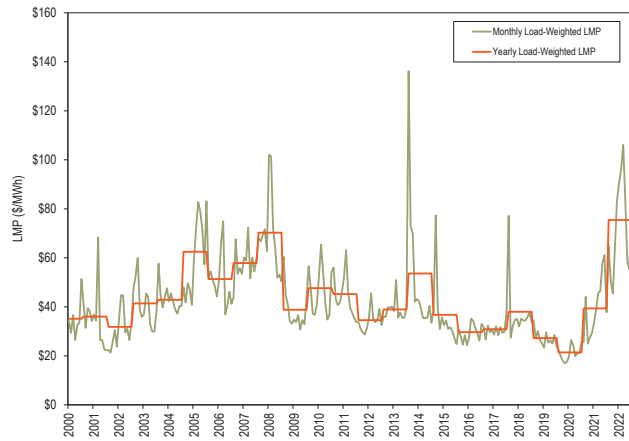
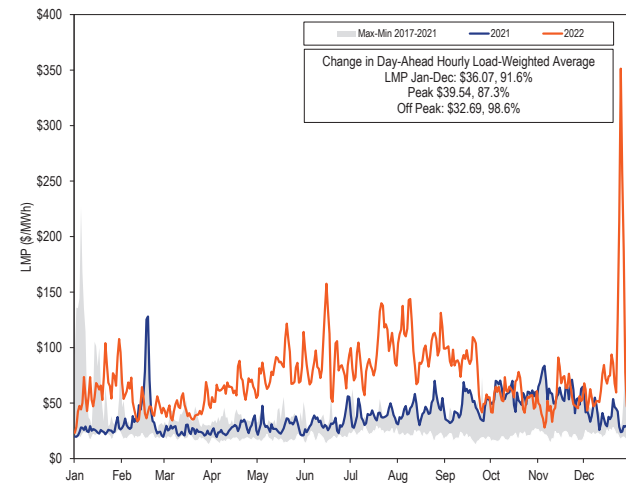


Figure 3-34 shows the day-ahead daily load-weighted average LMP in 2021 and 2022 compared to the historic five year price range.

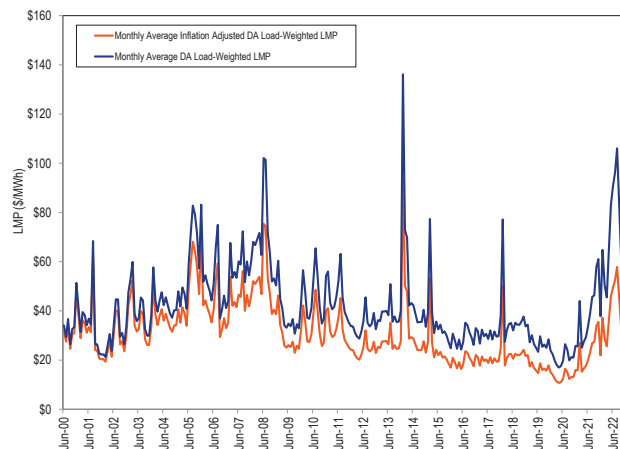
Figure 3-34 Day-ahead daily load-weighted average LMP: 2021 through 2022



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 2022.⁷⁸ Table 3-45 shows the PJM day-ahead load-weighted average LMP and inflation adjusted load-weighted average LMP for every year from 2000 through 2022. The nominal yearly PJM day-ahead load-weighted average LMP for 2022 was the highest since the first full year of the PJM day-ahead energy market in 2001. The inflation adjusted yearly PJM day-ahead load-weighted average LMP for 2022 was the fourth highest since the first full year of the PJM day-ahead energy market in 2001.

Figure 3-35 Day-ahead monthly load-weighted and inflation adjusted load-weighted average LMP: June 2000 through December 2022



⁷⁸ 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 January 12, 2023).

Table 3-45 Day-ahead yearly load-weighted and inflation adjusted load-weighted average LMP: 2000 through 2022

	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

Price Convergence

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

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

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

Where arbitrage incentives are created by systematic modeling differences, such as differences between the day-ahead and real-time modeled transmission contingencies and marginal loss calculations, virtual bids and offers cannot result in more efficient market

outcomes. Such offers may result in positive profits for the virtual but cannot change the underlying reason for the price difference. The virtual transactions will continue to profit from the activity for that reason regardless of the volume of those transactions and without improving the efficiency of the energy market. This is termed false arbitrage.

The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the day-ahead energy market. Price convergence does not necessarily mean a zero or even a very small difference in prices between day-ahead and real-time energy markets. There may be factors, from uplift charges to differences in risk that result in a competitive, market-based differential. In addition, convergence in the sense that day-ahead and real-time prices are equal at individual buses or aggregates on a day to day basis is not a realistic expectation as a result of uncertainty, lags in response time and modeling differences.

INCs, DECs and UTCs allow participants to benefit from price differences between the day-ahead and real-time energy market. In theory, virtual transactions receive positive profits, after uplift and administrative charges, when they contribute to price convergence, but with false arbitrage, profits result with little or no price convergence. The seller of an INC must buy energy in the real-time energy market to fulfill the financial obligation to provide energy. If the day-ahead price for energy is higher than the real-time price for energy, after uplift and administrative charges, the INC is profitable. The buyer of a DEC must sell energy in the real-time energy market to fulfill the financial obligation to buy energy. If the day-ahead price for energy is lower than the real-time price for energy, after uplift and administrative charges, the DEC is profitable.

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

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

Profits of Virtual Transactions

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

Table 3-46 shows, for cleared UTCs, the number of UTCs, the number of profitable UTCs, and the number of UTCs profitable at their source point, at their sink point, and at both points in 2021 and 2022. In 2022, 45.4 percent of all cleared UTC transactions were profitable. Of cleared UTC transactions, 67.3 percent were profitable on the source side and 33.5 percent were profitable on the sink side, but only 8.2 percent were profitable on both the source and sink side.

Table 3-46 Cleared UTC count with positive profits by source and sink point: 2021 and 2022⁷⁹

	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
2021	4,640,833	1,842,949	3,013,993	1,539,639	343,824	39.7%	64.9%	33.2%	7.4%
2022	5,761,480	2,617,375	3,879,604	1,931,895	472,474	45.4%	67.3%	33.5%	8.2%

Table 3-47 shows the number of cleared INC and DEC transactions and the number of profitable transactions in 2021 and 2022. Of cleared INC and DEC transactions in 2022, 65.0 percent of INCs were profitable and 34.5 percent of DECs were profitable.

Table 3-47 Cleared INC and DEC count with positive profits: 2021 and 2022

	Cleared INC	Profitable INC	Profitable INC Share	Cleared DEC	Profitable DEC	Profitable DEC Share
2021	2,266,256	1,441,970	63.6%	2,238,301	768,100	34.3%
2022	2,694,826	1,752,910	65.0%	2,416,863	832,894	34.5%

⁷⁹ Calculations exclude PJM administrative charges.

Figure 3-36 shows the positive, negative, and net daily profits for UTCs in 2022.

Figure 3-36 Positive, negative, and net daily UTC profits: January through December 2022⁸⁰

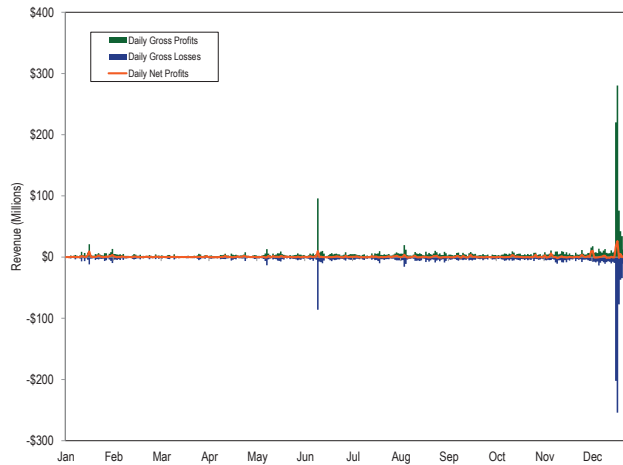
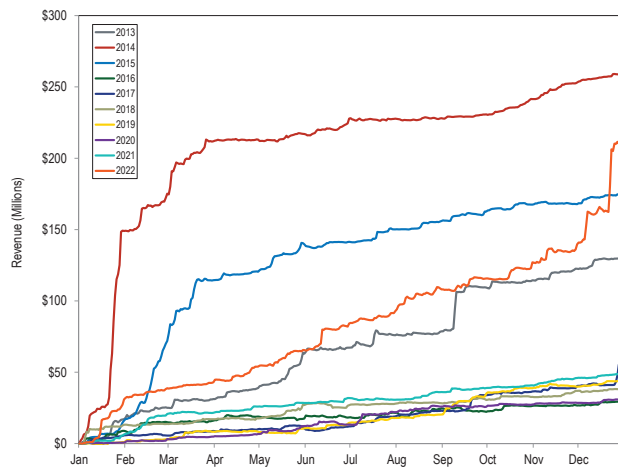


Table 3-48 shows UTC profits by month for January 2013 through December 2022. May 2016, September 2016, February 2017, June 2018, September 2020, and July 2021 were the only months in this seven year period in which monthly profits were negative. The totals include administrative charges for all months and uplift charges beginning in November 2020, when UTCs first became subject to the charges. UTC profits were \$211 million in 2022, higher than any year since 2014, with the largest monthly totals in December at \$75 million and January at \$31 million.

Figure 3-37 shows the cumulative UTC daily total net profits for each year from 2013 through 2022.⁸¹ Administrative charges are included for all dates, and uplift charges are included starting from November 1, 2020, when these charges were first applied to UTCs. Total UTC profits were higher in 2022 than any year since 2014.

Figure 3-37 Cumulative daily UTC profits: January 2013 through December 2022



⁸⁰ Calculations exclude PJM administrative charges.

⁸¹ UTCs paid uplift only after October 31, 2020.

Table 3-48 UTC profits by month: January 2013 through December 2022

	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

Figure 3-38 shows the positive, negative, and net daily profits for INCs and DECs in 2022. The most profitable days in 2022 were December 24 and 23, followed by June 12 and January 16. In all of these cases, but especially during the cold weather on December 23 and 24, DECs benefited from high real-time prices resulting from violated internal transmission constraints and other administrative adders such as reserve shortage penalty factors. Differences in the modeling of transmission constraints and other system constraints such as reserves between day ahead and real time, including the use of different constraint limits or a constraint being modeled in one market but not the other, remain a principal source of false arbitrage profits and a major reason for the overall profitability of virtual transactions.

Figure 3-38 Daily gross profits, gross losses, and net profits of all INC and DEC transactions: January through December, 2022⁸²

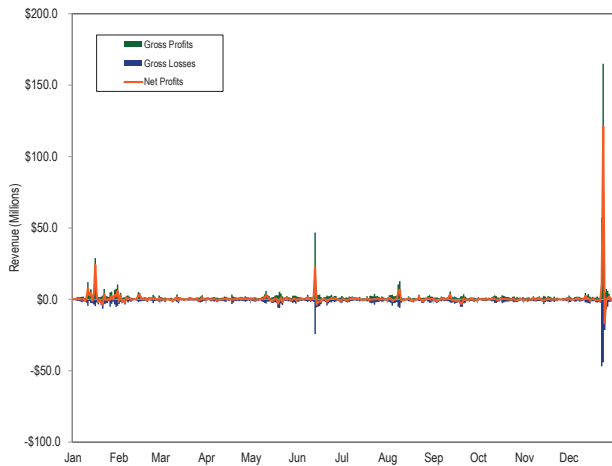


Figure 3-39 shows the positive, negative, and net daily profits for INCs in 2022.

82 Calculations exclude PJM administrative charges.

Figure 3-39 Daily gross profits, gross losses, and net profits for INC transactions: January through December, 2022⁸³

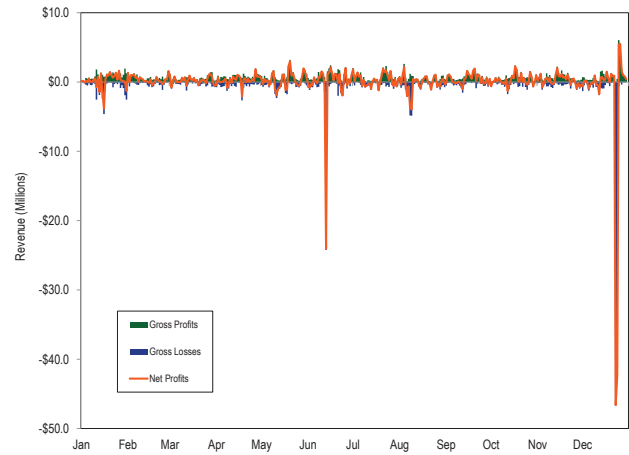
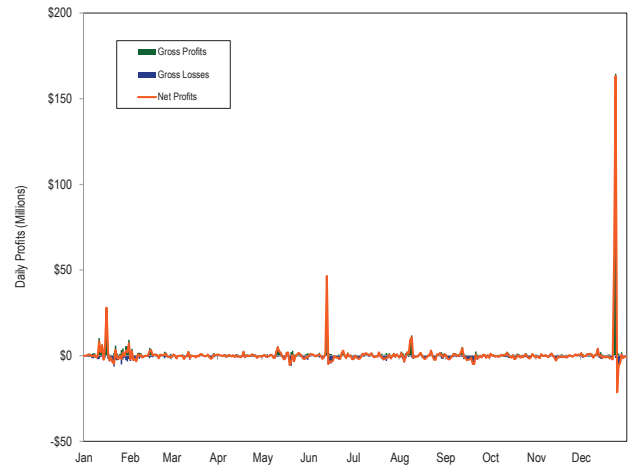


Figure 3-40 shows the positive, negative, and net daily profits for DECs in 2022.

Figure 3-40 Daily gross profits, gross losses, and net profits for DEC transactions: January through December, 2022⁸⁴



83 Calculations exclude PJM administrative charges.

84 Calculations exclude PJM administrative charges.

Figure 3-41 shows the cumulative INC and DEC daily profits in 2022. Most of the profits for DECs in 2022 resulted from high real-time prices in a relatively small number of hours due to factors that were not modeled in the day-ahead market. As a result, DECs were highly profitable on those days, most notably December 23 and 24, as well as January 16 and June 13, and total DEC profits were positive in 2022 despite losses in eight months. Virtual trading can be profitable under these circumstances without contributing to price convergence because the addition of virtual supply or demand in the day-ahead market does not and cannot correct for factors not included in the day-ahead model, such as the use of different transmission constraint limits in day ahead versus real time.

Figure 3-41 Cumulative daily INC and DEC profit: January through December, 2022

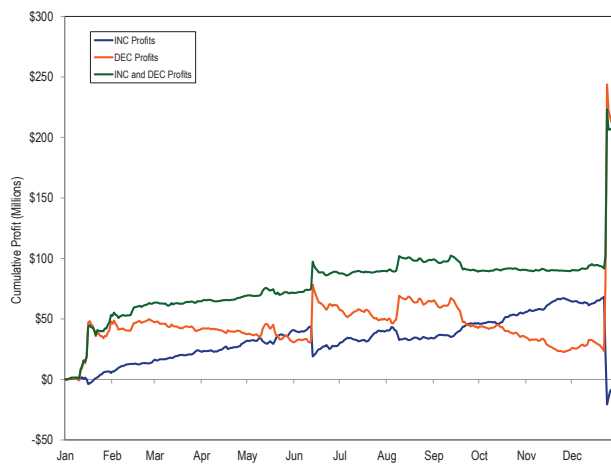


Table 3-49 shows INC and DEC profits by month in 2023.

Table 3-49 INC and DEC profits by month: January through December, 2022⁸⁵

Month	INCs	DECs	INCs and DECs
January	\$5,304,343	\$47,934,147	\$53,238,490
February	\$10,212,336	(\$205,054)	\$10,007,281
March	\$7,758,103	(\$6,437,415)	\$1,320,689
April	\$8,328,205	(\$3,797,965)	\$4,530,241
May	\$9,229,030	(\$6,834,483)	\$2,394,547
June	(\$12,275,210)	\$28,529,140	\$16,253,931
July	\$11,395,256	(\$9,559,207)	\$1,836,048
August	(\$5,844,044)	\$15,228,937	\$9,384,893
September	\$12,476,107	(\$22,352,533)	(\$9,876,426)
October	\$8,996,728	(\$7,481,662)	\$1,515,066
November	\$9,311,327	(\$10,285,092)	(\$973,766)
December	(\$70,935,902)	\$185,721,989	\$114,786,087
Total	(\$6,043,721)	\$210,460,802	\$204,417,080

⁸⁵ Versions of this table originally published in the 2021 Q2, Q3, and Annual State of the Market Reports had errors in the Total column which have been corrected.

All virtual transactions are subject to uplift charges. Each cleared MWh of a virtual transaction pays uplift at the daily operating reserve charge rates. 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 at the transaction's sink point, the day-ahead rate and RTO and regional deviation rates.

In 2022, assuming that all virtual transactions are subject to the full deviation charges, INCs paid a total of \$12.3 million in uplift, 112.4 percent of their gross revenues of \$10.9 million. DECs paid a total of \$22.0 million in uplift, 9.5 percent of their gross revenues of \$232.6 million. UTCs paid a total of \$52.6 million in uplift, 20.2 percent of their gross revenues of \$260.3 million.

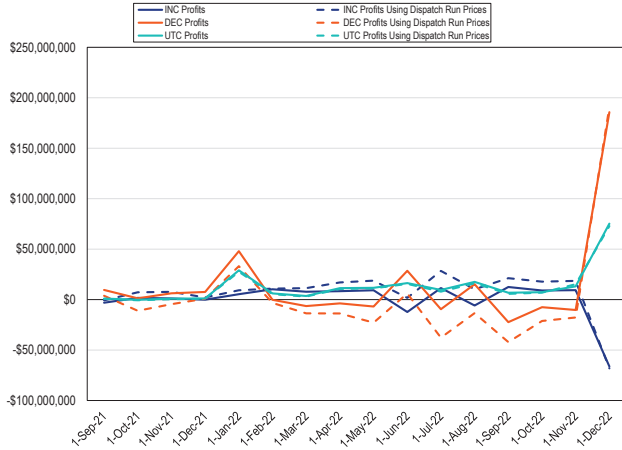
Effect of Fast Start Pricing on Virtuals

The implementation of fast start pricing on September 1, 2021, has resulted in changes to the settlement of virtual transactions. Prior to fast start pricing, virtual products were cleared and settled based on a single set of prices. The dispatch and pricing run prices were the same. With fast start pricing, all virtual products are cleared using day-ahead dispatch run prices, but pay and receive the day-ahead and real-time pricing run prices. The use of fast start pricing has a direct impact 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. Likewise, 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 divergences between day-ahead and real-time prices, which can be targeted by virtual traders. Because fast start pricing is more frequent in the real-time market, it means that, all else equal, real-time prices are higher than they otherwise would be, increasing the profitability of DECs and decreasing the profitability of INCs.

Figure 3-42 shows the total monthly profits received by INCs, DECs, and UTCs, compared to the profits they would have received if dispatch run prices had been used in settlement for each month since the initial implementation of fast start pricing in September 2021. Since its implementation, fast start pricing has consistently increased profits for DECs and decreased

profits for INCs but has not significantly affected profits for UTCs. Fast start pricing creates a difference between day-ahead and real-time prices. Virtual traders can benefit from this difference without contributing to price convergence.

Figure 3-42 Monthly profits for virtuals using pricing run versus dispatch run prices: September 1, 2021 through December 31, 2022



From the implementation of fast start pricing on September 1, 2021, through December 31, 2022, the cumulative difference in profit between the pricing run and the dispatch run for INCs was -\$115.0 million, the cumulative difference in profit for DECs was \$201.6 million, and the cumulative difference in profit for UTCs was \$11.4 million, a net total of \$98.0 million.

There are incentives to use virtual transactions to profit from price differences between the day-ahead and real-time energy markets, but there is no reason to believe that such activity will result in price convergence and no data to support that claim. As a general matter, virtual offers and bids are based on expectations about both day-ahead and real-time energy market conditions and reflect the uncertainty about conditions in both markets, about modeling differences and the fact that these conditions change hourly and daily. PJM markets do not provide a mechanism that could result in immediate convergence after a change in system conditions as there is at least a one day lag after any change in system conditions before offers could reflect such changes. PJM markets do not provide a mechanism that could ever result in convergence in the presence of modeling differences.

Substantial virtual trading activity does not guarantee that market power cannot be exercised in the day-ahead energy market. Hourly and daily price differences between the day-ahead and real-time energy markets fluctuate continuously and substantially from positive to negative. There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis.

Day-ahead and Real-time Prices

Table 3-50 shows the difference between the day-ahead and the real-time average LMP.

Table 3-50 Day-ahead and real-time average LMP (Dollars per MWh): 2021 and 2022⁸⁶

	2021				2022			
	Day-Ahead	Real-Time	Difference	Percent of Real-Time	Day-Ahead	Real-Time	Difference	Percent of Real-Time
Average	\$37.76	\$38.18	\$0.42	1.1%	\$70.77	\$73.53	\$2.76	3.8%
Median	\$32.15	\$30.59	(\$1.57)	(5.1%)	\$61.13	\$57.13	(\$3.99)	(7.0%)
Standard deviation	\$18.49	\$26.37	\$7.88	29.9%	\$37.79	\$115.77	\$77.98	67.4%
Peak average	\$44.06	\$44.54	\$0.47	1.1%	\$80.83	\$84.15	\$3.32	3.9%
Peak median	\$38.16	\$36.19	(\$1.97)	(5.4%)	\$71.58	\$67.73	(\$3.85)	(5.7%)
Peak standard deviation	\$20.61	\$31.44	\$10.83	34.5%	\$36.54	\$116.27	\$79.73	68.6%
Off peak average	\$32.23	\$32.60	\$0.37	1.1%	\$62.00	\$64.27	\$2.27	3.5%
Off peak median	\$27.40	\$26.82	(\$0.58)	(2.2%)	\$54.14	\$51.08	(\$3.06)	(6.0%)
Off peak standard deviation	\$14.28	\$19.27	\$4.99	25.9%	\$36.67	\$114.54	\$77.87	68.0%

Table 3-51 shows the difference between the day-ahead and the real-time load-weighted LMP in 2001 and 2022.

Table 3-51 Day-ahead and real-time load-weighted average LMP (Dollars per MWh): 2001 through 2022

	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%

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

Table 3-52 includes frequency distributions of the differences between the day-ahead and the real-time load-weighted LMP in 2021 and 2022.

Table 3-52 Frequency distribution by hours of real-time load-weighted LMP minus day-ahead load-weighted LMP (Dollars per MWh): 2021 and 2022

LMP	2021		2022	
	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< (\$200)	0	0.0%	16	0.2%
(\$200) to (\$100)	0	0.0%	34	0.6%
(\$100) to (\$50)	12	0.1%	77	1.4%
(\$50) to \$0	5,644	64.6%	5,747	67.1%
\$0 to \$50	2,962	98.4%	2,669	97.5%
\$50 to \$100	102	99.5%	121	98.9%
\$100 to \$200	29	99.9%	44	99.4%
\$200 to \$400	10	100.0%	23	99.7%
\$400 to \$800	1	100.0%	10	99.8%
>= \$800	0	100.0%	19	100.0%

Figure 3-43 shows the differences between day-ahead and real-time hourly average LMP in 2022.

The largest difference was \$3,499.93 per MWh on December 23, 2022. On June 13, 2022, the difference was \$2,474.45 per MWh.

Figure 3-43 Real-time hourly average LMP minus day-ahead hourly average LMP: 2022

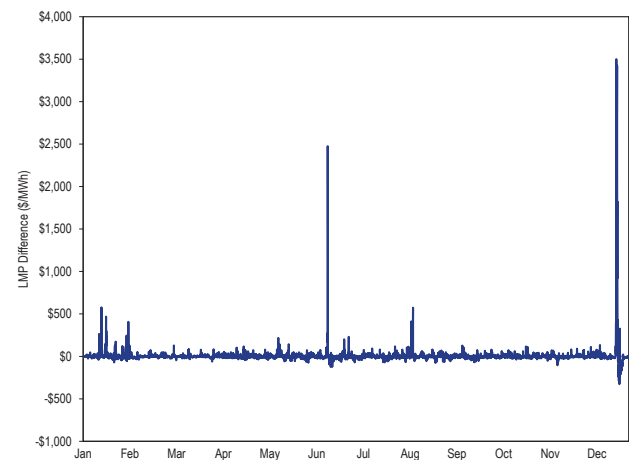
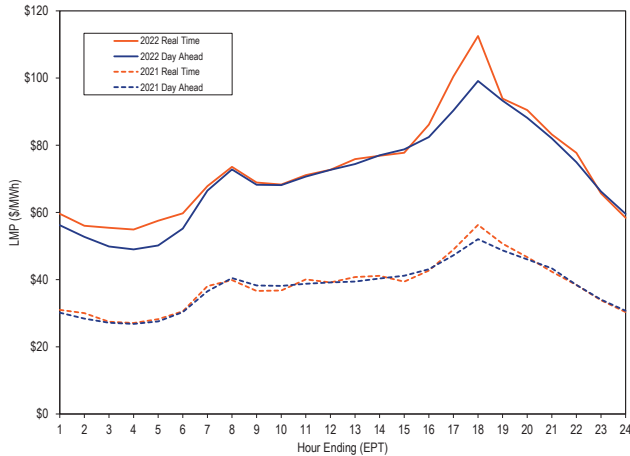


Figure 3-44 shows day-ahead and real-time load-weighted average LMP by hour of the day in 2021 and 2022.

Figure 3-44 System hourly average LMP: 2021 and 2022



Zonal LMP and Dispatch

Table 3-53 shows real-time zonal average and load-weighted average LMP in 2021 and 2022.

Table 3-53 Real-time zonal average and load-weighted average LMP (Dollars per MWh): 2021 and 2022

Zone	Real-Time Average LMP			Real-Time Load-Weighted Average LMP		
	2021	2022	Percent Change	2021	2022	Percent Change
ACEC	\$31.97	\$65.76	105.7%	\$34.13	\$74.27	117.6%
AEP	\$38.94	\$72.02	85.0%	\$40.31	\$77.54	92.4%
APS	\$39.05	\$72.98	86.9%	\$40.44	\$79.01	95.4%
ATSI	\$37.99	\$70.45	85.4%	\$39.47	\$74.96	89.9%
BGE	\$43.63	\$84.65	94.0%	\$45.77	\$95.44	108.5%
COMED	\$35.02	\$60.90	73.9%	\$37.00	\$66.25	79.1%
DAY	\$40.98	\$74.22	81.1%	\$42.92	\$80.43	87.4%
DUKE	\$39.68	\$72.62	83.0%	\$41.49	\$79.54	91.7%
DOM	\$42.69	\$89.37	109.3%	\$44.67	\$99.52	122.8%
DPL	\$37.84	\$71.57	89.1%	\$40.24	\$83.32	107.0%
DUQ	\$37.66	\$69.51	84.6%	\$39.17	\$74.76	90.9%
EKPC	\$39.25	\$72.89	85.7%	\$41.20	\$83.16	101.8%
JCPLC	\$32.55	\$67.30	106.8%	\$34.52	\$76.02	120.2%
MEC	\$37.86	\$75.09	98.3%	\$39.97	\$82.20	105.6%
OVEC	\$38.02	\$70.18	84.6%	\$37.98	\$71.39	87.9%
PECO	\$31.93	\$64.43	101.8%	\$33.55	\$71.67	113.6%
PE	\$36.50	\$69.62	90.7%	\$37.73	\$73.26	94.1%
PEPCO	\$42.48	\$81.80	92.6%	\$44.62	\$91.68	105.4%
PPL	\$34.58	\$69.69	101.5%	\$35.92	\$75.74	110.9%
PSEG	\$34.09	\$68.27	100.2%	\$35.78	\$74.74	108.9%
REC	\$36.46	\$70.15	92.4%	\$38.80	\$77.95	100.9%
PJM	\$38.18	\$73.53	92.6%	\$39.78	\$80.14	101.4%

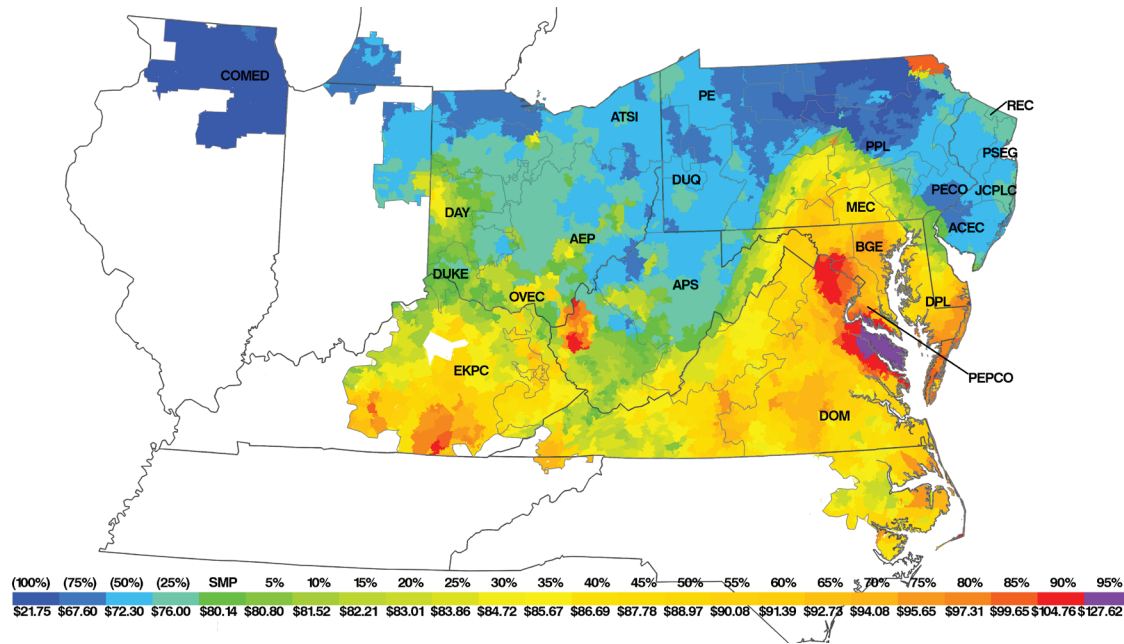
Table 3-54 shows day-ahead zonal average and load-weighted average LMP in 2021 and 2022.

Table 3-54 Day-ahead zonal average and load-weighted average LMP (Dollars per MWh): 2021 and 2022

Zone	Day-Ahead Average LMP			Day-Ahead Load-Weighted Average LMP		
	2021	2022	Percent Change	2021	2022	Percent Change
ACEC	\$31.89	\$62.97	97.5%	\$33.90	\$69.26	104.3%
AEP	\$38.49	\$70.09	82.1%	\$39.93	\$73.93	85.2%
APS	\$38.73	\$71.19	83.8%	\$40.05	\$74.23	85.4%
ATSI	\$38.25	\$69.44	81.5%	\$39.56	\$72.97	84.5%
BGE	\$43.36	\$81.83	88.7%	\$45.51	\$89.02	95.6%
COMED	\$34.76	\$60.39	73.7%	\$36.49	\$64.68	77.3%
DAY	\$40.73	\$72.59	78.2%	\$42.69	\$76.99	80.3%
DUKE	\$39.73	\$71.27	79.4%	\$41.42	\$76.45	84.5%
DOM	\$41.55	\$83.56	101.1%	\$43.66	\$90.84	108.1%
DPL	\$36.71	\$67.43	83.7%	\$39.43	\$75.88	92.4%
DUQ	\$37.73	\$68.18	80.7%	\$39.21	\$72.21	84.1%
EKPC	\$38.74	\$70.44	81.8%	\$40.90	\$75.60	84.8%
JCPLC	\$32.69	\$64.19	96.3%	\$34.52	\$70.21	103.4%
MEC	\$37.60	\$73.27	94.9%	\$39.66	\$78.62	98.2%
OVEC	\$37.77	\$68.64	81.8%	\$40.95	\$67.55	65.0%
PECO	\$31.79	\$61.80	94.4%	\$33.24	\$67.03	101.7%
PE	\$37.12	\$68.68	85.0%	\$38.93	\$72.00	85.0%
PEPCO	\$41.80	\$79.07	89.1%	\$44.05	\$86.23	95.8%
PPL	\$34.51	\$67.66	96.0%	\$35.73	\$71.72	100.8%
PSEG	\$33.31	\$64.99	95.1%	\$34.91	\$69.74	99.8%
REC	\$35.40	\$67.29	90.1%	\$38.00	\$73.49	93.4%
PJM	\$37.76	\$70.77	87.4%	\$39.37	\$75.44	91.6%

Figure 3-45 is a map of the real-time load-weighted average LMP in 2022. In the legend, green represents the system marginal price (SMP) and each increment to the right and left of the SMP represents five percent of the pricing nodes above and below the SMP.

Figure 3-45 Real-time load-weighted average LMP: 2022



Transmission Constraint Penalty Factors

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

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

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

Table 3-55 shows the frequency and average shadow price of transmission constraints in PJM. In 2022, there were 202,837 transmission constraint intervals

in the real-time market with a nonzero shadow price. For about 12 percent of these transmission constraint intervals, the line limit was violated, meaning that the flow exceeded the facility limit used in SCED.⁸⁷ For 84 percent of those violations, PJM had reduced the line rating. In those cases, the actual line limit was not violated. In 2022, the average shadow price of transmission constraints when the line limit used in SCED was violated was 7.4 times higher than when the transmission constraint was binding at its limit used in SCED. PJM activated the Greys Point-Harmony 115 kV contingency constraint in the Dominion Zone due to the outage of Lenexa-Dunnsville-Northern Neck 230 kV transmission line. The Greys Point-Harmony 115 kV contingency constraint accounted for nearly 10.1 percent of the violated transmission constraints in 2022.

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

⁸⁷ 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.

RTO on their constraints. The identified constraints are then modeled in the dispatch optimizations of the both RTOs. After every approved solution, the shadow prices are exchanged between the RTOs.

Table 3-55 Frequency and average shadow price of transmission constraints: 2021 and 2022

Description	Frequency (Constraint Intervals)		Average Shadow Price	
	2021	2022	2021	2022
Violated Transmission Constraints	13,782	24,016	\$1,599.42	\$1,743.92
Binding Transmission Constraints	102,529	104,562	\$183.04	\$236.39
Market to Market Transmission Constraints	53,756	74,259	\$459.12	\$505.01
All Transmission Constraints	170,067	202,837	\$385.09	\$513.23

Table 3-56 shows the frequency of violated transmission constraints by voltage level. In 2022, 91.8 percent of the violated transmission constraint intervals had a voltage level at or below 230 kV. Greys Point-Harmony 115 kV contingency constraint accounted for nearly 51.7 percent of the 115 kV violated transmission constraints in 2022. Of the 12,182 constraint violations at 230 kV, 53.2 percent were in the Dominion Zone, which had increased load from data centers and relatively higher natural gas prices compared to the rest of the PJM footprint.

Table 3-56 Frequency of PJM violated transmission constraints by voltage: 2021 and 2022

Voltage	2021		2022	
	Frequency (Constraint Intervals)	Percent	Frequency (Constraint Intervals)	Percent
1 kV	84	0.6%	76	0.3%
69 kV	1,581	11.5%	672	2.8%
115 kV	2,853	20.7%	4,693	19.5%
138 kV	4,457	32.3%	4,355	18.1%
161 kV	33	0.2%	68	0.3%
230 kV	3,381	24.5%	12,182	50.7%
345 kV	499	3.6%	502	2.1%
500 kV	860	6.2%	1,326	5.5%
765 kV	34	0.2%	142	0.6%
Total	13,782	100.0%	24,016	100.0%

Transmission penalty factors should be applied without discretion, but not without additional rules that prevent unintended consequences. PJM adopted the MMU's recommendation to remove the constraint relaxation logic and allow transmission penalty factors to set prices in the day-ahead and real-time markets for all internal transmission constraints. But the potential for prolonged and excessively high administrative pricing in the energy market due to transmission constraint penalty factors remains an issue that needs to be addressed. There can be situations in which the application of transmission penalty factors in real time for significant

periods creates manipulation opportunities for virtuals and creates inefficient wealth transfers when market participants do not have the ability to react to the high prices either on the supply or demand side.⁸⁸ This could be the result of a lengthy planned transmission outage, for example.⁸⁹ It can also result from PJM reducing the line limit in RT SCED below 100 percent of the actual line limit and triggering the transmission constraint penalty factor, while operating the system below the actual line limit for a prolonged period. PJM should not reduce transmission line limits in SCED to trigger the inclusion of transmission constraint penalty factors in price.

PJM also revised the tariff to list the conditions under which transmission penalty factors would be changed from their default value of \$2,000 per MWh. The new rules went into effect on February 1, 2019. The Commission approved the PJM and MISO joint filing to remove the constraint relaxation logic for market to market constraints on March 6, 2020. PJM and MISO implemented the changes to their dispatch software in the second half of 2020.

PJM routinely, based on discretion, reduces the line limit modeled in SCED to below 100 percent, generally to 95 percent of the actual limit, in order to trigger the use of transmission constraint penalty factors. Table 3-57 shows the frequency of changes to the transmission constraints for binding and violated transmission constraints in the PJM real-time market. In 2022, there were 20,063 or 84 percent of 24,016 violated transmission constraint intervals in the real-time market with constraint limit less than 100 percent of the actual constraint limit. In 2022, among the constraints with reduced constraint limits, the constraint limit was reduced on average by 5.9 percent.

⁸⁸ See Comments of the Independent Market Monitor for PJM, Docket No. EL22-26-000 et al. (February 1, 2022); 178 FERC ¶ 61,104 (2022).

⁸⁹ See *id.*

Table 3-57 Frequency of reduction in line ratings (constraint intervals): 2021 and 2022

Description	Frequency (Constraint Intervals)		Constraints with Reduced Line Limits (Constraint Intervals)		Average Reduction (Percentage)	
	2021	2022	2021	2022	2021	2022
Violated Transmission Constraints	13,782	24,016	13,319	20,063	12.1%	5.9%
Binding Transmission Constraints	102,529	104,562	101,378	101,046	7.3%	6.3%
Market to Market Transmission Constraints	53,756	74,259	18,180	17,702	6.5%	5.6%
All Transmission Constraints	170,067	202,837	132,877	138,811	7.7%	6.2%

Table 3-58 shows the reasons provided by the PJM dispatchers for changing the line rating for violated transmission constraints. In 2022, of the 20,063 violated transmission constraints with reduced line ratings, 2,901 or 14 percent were reduced because the relief calculated by the SCED optimization was less than the dispatcher's desired relief for the transmission constraint. No reason was provided for 14,358 instances, or 72 percent of all the instances. The MMU recommends that PJM end the practice of discretionary reductions in transmission line ratings modeled in SCED. This practice has significant market impacts by increasing prices above the level that would exist if the actual line rating were enforced.

Table 3-58 PJM's reasons for reduction in line ratings (constraint intervals): 2021 and 2022

Reason	Constraint Intervals		Average Reduction (Percentage)	
	2021	2022	2021	2022
No reason provided	6,866	14,358	4.5%	4.3%
Prepositioning of generation resources to support an operational requirement	148	405	11.5%	9.2%
Inadequate relief calculated by the SCED optimization	3,402	2,901	9.2%	7.7%
Transmission owner identified the flow on their constraint to be greater than PJM's calculated flow on the same constraint.	427	594	8.6%	8.0%
Modeled constraint is a thermal surrogate	998	183	80.6%	70.1%
Power flow on the constraint is volatile due to various system conditions	1,478	1,622	8.8%	8.1%
Total	13,319	20,063	12.1%	5.9%

Table 3-59 shows the impact on LMP of PJM dispatchers reducing the line ratings of transmission constraints and causing artificial line limit violations.⁹⁰ The transmission penalty factor contribution to the load weighted average LMP in 2022 was \$4.68 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 -0.10 per MWh or 102.2 percent lower. On June 13, 2022, PJM

reduced the line limit of several transmission constraints including the Conastone-Peach Bottom 500 kV transmission constraint in the SCED dispatch software. The Conastone-Peach Bottom constraint was violated even though the state estimator flows on the constraint never exceeded the actual ambient temperature adjusted line rating. The constraint violation led to more than \$700 per MWh penalty factor added to the system marginal price for energy during some intervals on June 13, 2022.

Table 3-59 Real-time LMP impact of reduced line limits for PJM transmission constraints (Dollars per MWh): 2021 and 2022

Line Limit Scenario for Violated Constraints	Contribution to LMP	
	2021	2022
Line Limits Reduced by PJM (Actual)	\$3.31	\$4.63
Hypothetical Use of Full Line Limits	\$0.74	(\$0.10)
Change in Contribution to LMP	(\$2.57)	(\$4.73)
Percent Change in Contribution to LMP	(77.7%)	(102.2%)

Table 3-60 shows the frequency of changes to the magnitude of transmission penalty factors for binding and violated transmission constraints in the PJM Real-Time Energy Market. In 2022, there were 20,243 or 84 percent of violated transmission constraint intervals in the real-time market with a transmission penalty factor equal to the default \$2,000 per MWh. Of the 3,706 constraint intervals violated with a penalty factor reduced below the default of \$2,000 per MWh, the Greys Point-Harmony 115 kV contingency constraint accounted for nearly 42 percent in 2022. On August 9, 2022, PJM increased the transmission penalty factor to \$3,000 for West Transfer Interface constraint. For four five minute intervals, the transmission penalty factor set the shadow price of the West Transfer Interface constraint at \$3,000 per MWh and for three five minute intervals, the shadow price of the West Transfer Interface constraint was between \$2,000 and \$3,000.

⁹⁰ The MMU calculates the impact on system prices based on analysis using sensitivity factors. The transmission penalty factor contribution with actual line limits is not based on a counterfactual redispatch of the system. See Technical Reference for PJM Markets, "Calculation and Use of Generator Sensitivity/Unit Participation Factors," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 3-60 Frequency of changes to the magnitude of transmission penalty factor (constraint intervals): 2021 and 2022

Description	2021			2022		
	\$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	10,040	190	3,552	20,243	67	3,706
Binding Transmission Constraints	100,359	26	2,144	103,669	32	861
Market to Market Transmission Constraints	11,707	-	42,049	9,292	31	64,936
All Transmission Constraints	122,106	216	47,745	133,204	130	69,503

Transmission constraint penalty factors frequently set prices when PJM models a surrogate constraint to limit the dispatch of a generator that would experience voltage instability at its full output due to a transmission outage. In 2022, there were 1,223 five minute intervals during which PJM reduced the output of generators to manage instability. Changes to the surrogate constraint limit that exceed the unit's ability to reduce output cause constraint violations. Constraint violations also occur when the unit follows the regulation signal or increases its minimum operating parameters above the surrogate constraint limit. Prices set at the \$2,000 per MWh penalty factor are not useful signals to the market under these conditions and create false arbitrage opportunities for virtuals.

PJM used CT pricing logic until the implementation of fast start pricing on September 1, 2021, to force otherwise uneconomic resources to be marginal and set price in the day-ahead and real-time market solutions. In the event PJM committed a resource that is uneconomic and/or offered with inflexible parameters, PJM used CT pricing logic to model a constraint with a variable flow limit, paired with an artificial override of the inflexible resource's economic minimum, to force the resource to be marginal in the PJM market solution.⁹¹ Frequently, PJM dispatchers also manually overrode the transmission violation penalty factor of the constraint to match the offer price of the resource to artificially control the shadow price of the constraint.

PJM's use of CT pricing logic was inconsistent with the efficient market dispatch and pricing. For that reason, in 2019 FERC declared CT pricing logic to be unjust and unreasonable.⁹² PJM continues to use similar methods to artificially change the prices, like using thermal

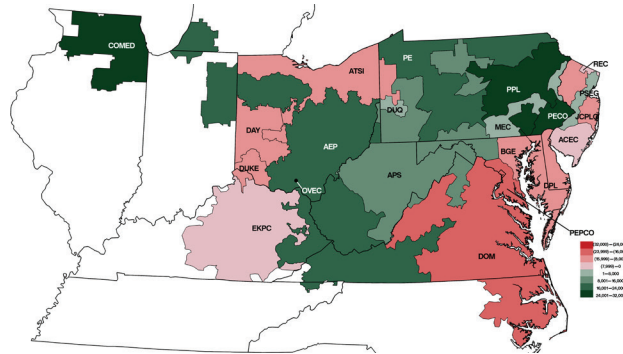
surrogates and forcing units to be marginal. These practices can lead to inefficient market outcomes.

Net Generation by Zone

Figure 3-46 shows the difference between the PJM real-time generation and real-time load by zone for 2022.

Figure 3-46 is color coded using a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation than load, with darker shades meaning greater amounts of net generation or load. Table 3-61 shows the difference between the real-time generation and real-time load by zone for 2021 and 2022.

Figure 3-46 Map of real-time generation less real-time load by zone: 2022⁹³



⁹¹ PJM dispatchers generally log the resources paired with a constraint in the CT pricing logic. The data presented is based on PJM dispatcher logs.

⁹² 167 FERC ¶ 61,058 at P 69 (2019).

⁹³ Real-time zonal generation data for the map and corresponding table is based on the zonal designation for every bus listed in the most current PJM LMP bus model, which can be found at <<http://www.pjm.com/markets-and-operations/energy/lmp-model-info.aspx>>.

Table 3-61 Real-time generation less real-time load by zone (GWh): 2021 and 2022

Zonal Generation and Load (GWh)						
Zone	2021			2022		
	Generation	Load	Net	Generation	Load	Net
ACEC	2,848	9,871	(7,023)	2,795	9,915	(7,120)
AEP	140,958	124,326	16,631	143,026	125,587	17,439
APS	54,981	48,015	6,966	57,671	48,565	9,106
ATSI	50,703	64,510	(13,807)	56,974	65,221	(8,247)
BGE	18,197	30,462	(12,266)	17,529	30,507	(12,977)
COMED	131,325	92,873	38,452	135,128	92,483	42,645
DAY	1,160	16,863	(15,703)	1,393	16,984	(15,591)
DUKE	17,874	26,091	(8,217)	17,035	26,220	(9,185)
DOM	97,159	106,128	(8,969)	92,061	112,103	(20,041)
DPL	4,438	18,342	(13,905)	5,439	18,556	(13,117)
DUQ	15,974	13,018	2,955	16,418	13,120	3,298
EKPC	10,092	12,763	(2,671)	10,253	13,300	(3,048)
JCPLC	7,771	22,016	(14,244)	9,393	22,057	(12,664)
MEC	18,892	15,413	3,479	19,273	15,529	3,744
OVEC	10,064	115	9,949	11,048	116	10,931
PECO	73,258	38,436	34,823	72,577	38,648	33,930
PE	41,005	16,657	24,348	35,977	16,735	19,242
PEPCO	12,176	27,771	(15,595)	10,717	27,980	(17,263)
PPL	68,075	40,205	27,870	66,913	40,822	26,092
PSEG	43,375	42,138	1,237	45,041	42,757	2,284
REC	0	1,411	(1,411)	0	1,420	(1,420)

Net Generation and Load

PJM sums all negative (injections) and positive (withdrawals) at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) at each generation bus when calculating net generation. Netting withdrawals and injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, power to onsite customers, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

The zonal load-weighted LMP is calculated by weighting the zone's load bus LMPs by the zone's load bus accounting load. The definition of injections and withdrawals of energy as generation or load affects PJM's calculation of zonal load-weighted LMP.

The MMU recommends that during intervals when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU also recommends that during intervals when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP.

Fuel Prices, LMP, and Dispatch

Energy Production by Fuel Source

Table 3-62 shows PJM generation by fuel source in GWh for 2021 and 2022. In 2022, generation from coal units decreased 9.1 percent, generation from natural gas units increased 6.8 percent, and generation from oil increased 17.8 percent compared to 2021. Wind and solar output rose by 16.2 percent compared to 2021, supplying 6.8 percent of PJM energy in 2022.

Table 3-62 Generation (By fuel source (GWh)): 2021 and 2022^{94 95}

	2021		2022		Change in Output
	GWh	Percent	GWh	Percent	
Coal	184,412.3	22.2%	167,650.0	20.0%	(9.1%)
Bituminous	163,753.6	19.7%	144,880.5	17.2%	(11.5%)
Sub Bituminous	14,421.7	1.7%	16,210.5	1.9%	12.4%
Other Coal	6,237.0	0.7%	6,558.9	0.8%	5.2%
Nuclear	272,670.4	32.8%	271,522.1	32.3%	(0.4%)
Gas	314,885.1	37.9%	335,974.2	40.0%	6.7%
Natural Gas CC	289,136.6	34.8%	309,420.5	36.8%	7.0%
Natural Gas CT	19,894.4	2.4%	18,581.9	2.2%	(6.6%)
Natural Gas Other Units	4,132.1	0.5%	6,501.5	0.8%	57.3%
Other Gas	1,722.0	0.2%	1,470.4	0.2%	(14.6%)
Hydroelectric	16,624.8	2.0%	15,995.8	1.9%	(3.8%)
Pumped Storage	5,037.3	0.6%	6,092.9	0.7%	21.0%
Run of River	10,278.6	1.2%	7,945.5	0.9%	(22.7%)
Other Hydro	1,308.9	0.2%	1,957.4	0.2%	49.6%
Wind	27,651.4	3.3%	31,491.0	3.7%	13.9%
Waste	4,475.9	0.5%	4,056.0	0.5%	(9.4%)
Oil	2,290.7	0.3%	2,698.9	0.3%	17.8%
Heavy Oil	65.6	0.0%	76.4	0.0%	16.4%
Light Oil	524.4	0.1%	878.9	0.1%	67.6%
Diesel	27.7	0.0%	163.1	0.0%	489.3%
Other Oil	1,673.1	0.2%	1,580.5	0.2%	(5.5%)
Solar	7,412.2	0.9%	9,243.0	1.1%	24.7%
Battery	36.5	0.0%	25.4	0.0%	(30.2%)
Biofuel	1,191.7	0.1%	1,371.1	0.2%	15.1%
Total	831,650.8	100.0%	840,027.6	100.0%	1.0%

Table 3-63 Monthly generation (By fuel source (GWh)): 2022

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Coal	22,228.7	16,327.3	12,398.3	11,936.9	12,088.1	13,716.5	17,023.8	17,496.1	10,866.8	7,691.5	9,919.3	15,956.6	167,650.0
Bituminous	19,342.3	14,273.9	11,048.4	10,195.6	10,484.3	11,751.9	14,478.5	15,292.1	9,694.2	6,671.3	8,534.2	13,113.9	144,880.5
Sub Bituminous	2,221.2	1,504.5	921.9	1,280.6	987.6	1,450.8	1,948.2	1,626.8	633.2	485.9	836.5	2,313.4	16,210.5
Other Coal	665.2	548.9	428.1	460.6	616.3	513.7	597.1	577.2	539.5	534.3	548.7	529.3	6,558.9
Nuclear	25,053.1	21,743.6	22,442.0	19,429.4	22,653.9	23,188.5	24,069.0	23,676.5	22,164.6	20,532.7	22,092.6	24,476.2	271,522.1
Gas	27,493.7	24,136.2	25,884.6	20,621.7	23,665.8	30,298.9	36,695.7	36,257.9	30,389.4	26,859.9	25,379.3	28,291.1	335,974.2
Natural Gas CC	24,756.0	23,282.6	25,157.0	19,324.2	21,897.6	27,382.7	32,328.0	32,364.7	28,251.3	25,224.1	23,397.6	26,054.8	309,420.5
Natural Gas CT	1,888.3	606.2	462.2	983.7	1,301.7	2,102.8	2,983.1	2,747.8	1,548.4	1,084.5	1,309.7	1,563.3	18,581.9
Natural Gas Other Units	723.7	130.8	131.5	190.5	334.2	691.8	1,256.3	1,019.4	472.5	431.7	557.7	561.4	6,501.5
Other Gas	125.8	116.6	133.9	123.4	132.4	121.6	128.3	126.0	117.2	119.6	114.2	111.6	1,470.4
Hydroelectric	1,264.8	1,315.6	1,670.1	1,403.0	1,580.1	1,461.8	1,353.0	1,418.8	1,184.9	794.2	1,077.3	1,472.2	15,995.8
Pumped Storage	422.5	395.5	426.7	369.0	540.3	680.7	735.4	763.5	599.5	322.3	385.0	452.5	6,092.9
Run of River	719.9	806.5	1,120.8	916.2	855.6	530.8	352.9	381.6	412.4	358.3	585.4	905.3	7,945.5
Other Hydro	122.3	113.7	122.6	117.8	184.2	250.3	264.8	273.7	173.0	113.7	106.9	114.4	1,957.4
Wind	3,072.6	3,256.3	3,386.6	3,298.2	2,676.7	1,803.4	1,474.0	1,242.9	1,655.0	2,945.5	3,584.4	3,095.4	31,491.0
Waste	337.6	288.5	313.8	331.2	363.8	342.5	377.7	366.3	318.6	325.0	347.1	344.0	4,056.0
Oil	313.5	191.7	184.7	166.7	103.6	174.0	237.5	269.9	157.0	139.8	146.0	614.6	2,698.9
Heavy Oil	2.8	4.7	0.0	0.0	16.2	5.1	22.4	7.5	0.0	0.4	0.0	17.3	76.4
Light Oil	120.4	33.0	20.4	14.2	16.3	34.3	84.6	108.3	5.9	8.5	44.6	388.5	878.9
Diesel	26.1	7.0	2.8	0.3	0.3	3.9	4.4	12.8	0.0	1.1	2.4	101.9	163.1
Other Oil	164.2	147.0	161.6	152.2	70.9	130.7	126.0	141.3	151.0	129.8	99.0	106.8	1,580.5
Solar	427.0	565.0	754.2	956.1	945.1	1,103.4	998.7	989.8	877.8	689.8	523.9	412.2	9,243.0
Battery	2.2	1.5	2.1	1.8	2.0	2.0	2.0	1.8	2.1	2.2	3.3	2.5	25.4
Biofuel	131.3	120.6	107.9	97.2	114.9	131.0	127.6	139.9	102.9	93.4	80.1	124.3	1,371.1
Total	80,324.4	67,946.4	67,144.4	58,242.3	64,194.0	72,221.9	82,358.9	81,859.8	67,719.1	60,074.0	63,153.3	74,789.2	840,027.6

⁹⁴ 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.

⁹⁵ Other Gas includes: Landfill, Propane, Butane, Hydrogen, Gasified Coal, and Refinery Gas. Other Coal includes: Lignite, Liquefied Coal, Gasified Coal, and Waste Coal. Other oil includes: Gasoline, Jet Oil, Kerosene, and Petroleum-Other.

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

Table 3-64 Day-ahead and real-time average generation (By fuel source (GWh)): 2022

	2022					
	Day-Ahead		Real-Time		Difference	Percent Difference
	GWh	Percent	GWh	Percent		
Coal	170,162.2	20.4%	167,650.0	20.0%	(2,512.3)	(1.5%)
Bituminous	147,384.8	17.6%	144,880.5	17.2%	(2,504.3)	(1.7%)
Sub Bituminous	16,441.7	2.0%	16,210.5	1.9%	(231.2)	(1.4%)
Other Coal	6,335.8	0.8%	6,558.9	0.8%	223.1	3.5%
Nuclear	272,299.1	32.6%	271,522.1	32.3%	(777.0)	(0.3%)
Gas	336,505.2	40.3%	335,974.2	40.0%	(531.0)	(0.2%)
Natural Gas CC	312,731.9	37.4%	309,420.5	36.8%	(3,311.4)	(1.1%)
Natural Gas CT	15,314.9	1.8%	18,581.9	2.2%	3,267.0	21.3%
Natural Gas Other Units	6,934.4	0.8%	6,501.5	0.8%	(432.9)	(6.2%)
Other Gas	1,524.0	0.2%	1,470.4	0.2%	(53.7)	(3.5%)
Hydroelectric	16,174.8	1.9%	15,995.8	1.9%	(179.0)	(1.1%)
Pumped Storage	8,087.8	1.0%	6,092.9	0.7%	(1,994.9)	(24.7%)
Run of River	8,087.0	1.0%	7,945.5	0.9%	(141.5)	(1.7%)
Other Hydro	0.0	0.0%	1,957.4	0.2%	1,957.4	NA
Wind	25,391.0	3.0%	31,491.0	3.7%	6,100.1	24.0%
Waste	3,915.2	0.5%	4,056.0	0.5%	140.8	3.6%
Oil	2,418.9	0.3%	2,698.9	0.3%	280.0	11.6%
Heavy Oil	97.0	0.0%	76.4	0.0%	(20.6)	(21.2%)
Light Oil	603.2	0.1%	878.9	0.1%	275.7	45.7%
Diesel	177.2	0.0%	163.1	0.0%	(14.1)	(7.9%)
Other Oil	1,541.5	0.2%	1,580.5	0.2%	39.0	2.5%
Solar	6,749.1	0.8%	9,243.0	1.1%	2,493.8	37.0%
Battery	0.0	0.0%	25.4	0.0%	25.4	NA
Biofuel	1,518.6	0.2%	1,371.1	0.2%	(147.5)	(9.7%)
Total	835,134.2	100.0%	840,027.6	100.0%	4,893.3	0.6%

Table 3-65 shows generation by natural gas, coal, nuclear and other fuel types in the real-time energy market since 2008.

Table 3-65 Share of generation by fuel source: 2008 through 2022

	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%

Fuel Diversity

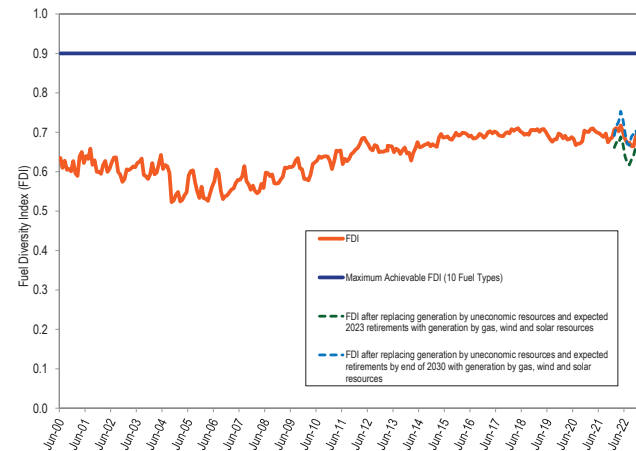
Figure 3-47 shows the fuel diversity index (FDI_c) for PJM energy generation.⁹⁶ The FDI_c is defined as $1 - \sum_{i=1}^N s_i^2$, where s_i is the share of fuel type i . The minimum possible value for the FDI_c is zero, corresponding to all generation from a single fuel type. The maximum possible value for the FDI_c 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_c are the 10 primary fuel sources in Table 3-62 with nonzero generation values. As fuel diversity has increased, seasonality in the FDI_c has decreased and the FDI_c has exhibited less volatility. Since 2012, the monthly FDI_c has been less volatile as a result of the decline in the share of coal from 51.3 percent prior to 2012 to 31.2 percent from 2012 through 2022. A significant drop in the FDI_c 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.⁹⁷ The increasing trend that began in 2008 is a result of decreasing coal generation, increasing gas generation and increasing wind generation. Coal generation as a share of total generation was 54.9 percent for 2008 and 20.0 percent for 2022. Gas generation as a share of total generation was 7.4 percent for 2008 and 40.0 percent for 2022. Wind and solar generation as a share of total generation was 0.4 percent for 2008 and 4.8 percent for 2022.

The FDI_c decreased 0.7 percent in 2022 compared to 2021.

The FDI_c was also used to measure the impact on fuel diversity of potential retirements in 2023 and through 2030.⁹⁸ A total of 8,963 MW of capacity are at risk of retirement in 2023, consisting of 6,086 MW currently planning to retire in 2023 and 2,877 MW expected to retire by the end of 2023 for regulatory reasons. This capacity consists primarily of coal plants and gas peaker units. The units expected to retire by the end of 2023 generated 83,614.1 GWh in 2022. The dashed line (green) in Figure 3-47 shows a counterfactual result

for FDI_c assuming the 83,614.1 GWh of generation from uneconomic units and expected 2023 retirements were replaced by gas, wind and solar generation.⁹⁹ The FDI_c for 2022 under this counterfactual assumption would have been 5.7 percent lower than the actual FDI_c. A total of 51,757 MW of capacity are at risk of retirement by the end of 2030, consisting of 6,628 MW currently planning to retire, 23,509 MW expected to retire for regulatory reasons, and 21,621 MW expected to be uneconomic. The identified units generated 104,111.3 GWh in 2022. Replacing this generation with gas, wind and solar generation results in a counterfactual FDI_c that is 1.6 percent higher than the actual FDI_c.¹⁰⁰ The dashed line (blue) in Figure 3-47 shows a counterfactual result for FDI_c assuming that this generation is replaced with gas, wind and solar generation.

Figure 3-47 Fuel diversity index for monthly generation: June 2000 through December 2022



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, purchased on a term contract or a spot basis. A generator could purchase pipeline transportation and purchase commodity

⁹⁶ 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.

⁹⁷ See the 2019 State of the Market Report for PJM, Volume II, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton Zones occurred in October 2004.

⁹⁸ See Units At Risk of Retirement in the 2022 State of the Market Report for PJM, Section 7: Net Revenue.

⁹⁹ It is assumed that 10,035.2 GWh of the replacement energy is from new wind and solar units. This value represents the increase over 2022 levels in renewable generation that is required by RPS in 2023. The split between solar (70.4 percent) and wind (29.6 percent) is based on queue data and 2022 capacity factors in Table 8-33 and Table 8-36.

¹⁰⁰ It is assumed that 78,355.5 GWh of the replacement energy is from new wind and solar units. This value represents the increase over 2022 levels in renewable generation that is required by RPS in 2030. The split between solar (70.4 percent) and wind (29.6 percent) is based on queue data and 2022 capacity factors in Table 8-33 and Table 8-36.

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 contracted 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.

The natural gas transportation gas day starts at 1000 EPT each day and runs for 24 hours. Pipeline contracts for firm transportation designate the location of the firm entitlements for receipt and for deliveries. Firm service is guaranteed as long as the nomination cycles are followed, except during force majeure events. The transportation contract or tariff may also provide for locations on a secondary firm basis. In order to have the highest priority level of service, the receipt and delivery of gas must be at the receipt and delivery points designated in the contract.

In order to be able to actually use the purchased pipeline transportation service, generation owners must nominate the flow of gas by defined deadlines. Some pipelines also impose site specific restrictions that limit the ability of generators to nominate and schedule gas beyond the nomination deadlines. Table 3-66 shows the approved nomination deadlines and corresponding start time of gas flow.¹⁰¹ Pipelines provide that firm service requests may replace, or bump, interruptible nominations on the pipeline under defined conditions.

Table 3-66 Approved nomination deadlines

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

¹⁰¹ Nomination deadlines approved in FERC Order No. 809, implemented April 1, 2016.

In 2021 and 2022, 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 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, Eastern Gas Transmission & Storage, Eastern Shore, Horizon Pipeline, Natural Gas Pipeline, Panhandle Eastern, Texas Eastern, Tennessee Gas Pipeline and Transcontinental Gas Pipeline.

Pipeline operators use restrictive and inflexible rules to manage the balance of supply and demand during constrained operating conditions determined by the pipeline. The independent operations of geographically overlapping pipelines during extreme conditions highlights the shortcomings of a gas pipeline network that relies on individual pipelines to manage the balancing of total supply and demand across a broad geographical area that includes multiple pipelines. The independent operational restrictions imposed by pipelines and the impact on electric generators during extreme conditions demonstrate the potential benefits to creating a separate gas ISO/RTO structure to coordinate the supply of gas across pipelines and with the electric RTOs and to facilitate the interoperability of the pipelines in an explicit network.

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

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

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 3-67 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 2022, coal units were 10.0 percent and natural gas units were 75.2 percent of marginal resources. In 2022,

natural gas combined cycle units were 61.7 percent of marginal resources. In 2021, coal units were 14.1 percent and natural gas units were 71.7 percent of the total marginal resources. In 2021, natural gas combined cycle units were 59.7 percent of the total marginal resources. In 2022, 62.4 percent of the wind marginal units had negative offer prices, 33.2 percent had zero offer prices and 4.4 percent of the wind marginal units had positive offer prices. In 2021, 77.8 percent of the wind marginal units had negative offer prices, 20.9 percent had zero offer prices and 1.4 percent had positive offer prices.

The proportion of marginal nuclear units decreased from 1.00 percent in 2021 to 0.39 percent in 2022. Most nuclear units are offered as fixed generation in the PJM market. A small number of nuclear units were offered with a dispatchable range since 2015. The dispatchable nuclear units do not always respond to dispatch instructions.

PJM implemented fast start pricing on September 1, 2021. The marginal resources shown in Table 3-67 are from the pricing run, which may not be the same as marginal resources from the dispatch run.

Table 3-67 Type of fuel used and technology (By real-time marginal units): 2018 through 2022¹⁰²

Fuel	Technology	2018	2019	2020	2021	2022
Gas	CC	53.45%	62.13%	64.33%	59.75%	61.66%
Gas	CT	7.80%	5.97%	5.89%	10.06%	11.26%
Wind	Wind	2.56%	3.81%	6.75%	11.04%	11.12%
Coal	Steam	27.26%	24.37%	17.53%	14.15%	10.02%
Oil	CT	4.58%	0.49%	1.25%	1.13%	2.25%
Gas	Steam	1.68%	1.29%	2.12%	1.17%	1.42%
Gas	RICE	0.41%	0.00%	0.29%	0.67%	0.86%
Other	Solar	0.12%	0.07%	0.33%	0.76%	0.74%
Uranium	Steam	1.04%	1.31%	1.35%	1.00%	0.39%
Oil	RICE	0.42%	0.00%	0.04%	0.06%	0.11%
Oil	CC	0.13%	0.01%	0.00%	0.02%	0.06%
Other	Steam	0.15%	0.06%	0.03%	0.08%	0.05%
Municipal Waste	Steam	0.04%	0.02%	0.02%	0.02%	0.04%
Oil	Steam	0.29%	0.03%	0.06%	0.06%	0.03%
Municipal Waste	RICE	0.04%	0.00%	0.00%	0.00%	0.00%
Landfill Gas	CT	0.00%	0.01%	0.01%	0.01%	0.00%
Municipal Waste	CT	0.02%	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 3-48 shows the type of fuel used by marginal resources in the real-time energy market since 2004. The role of coal as a marginal resource has declined while the role of gas as a marginal resource has increased.

¹⁰² The unit type RICE refers to Reciprocating Internal Combustion Engines.

Figure 3-48 Type of fuel used (By real-time marginal units): 2004 through 2022

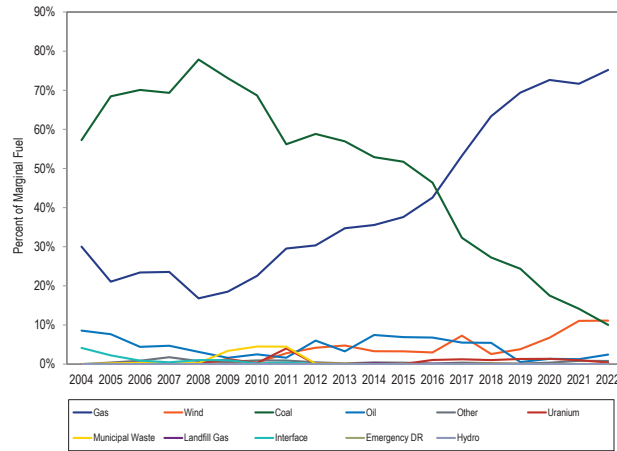


Table 3-68 shows the type of fuel and technology by fast start marginal resources and other marginal resources in the real-time energy market in 2022. In 2022, marginal fast start resources accounted for 7.76 percent of all marginal resources in the pricing run.

Table 3-68 Fuel type and technology (Real-time marginal units and fast start marginal units): 2022

Fuel	Technology	2022		
		Fast Start	Other	Both
Coal	Steam	0.00%	10.02%	10.02%
Gas	CC	0.00%	61.66%	61.66%
Gas	CT	5.92%	5.33%	11.26%
Gas	RICE	0.79%	0.06%	0.86%
Gas	Steam	0.00%	1.42%	1.42%
Landfill Gas	CT	0.00%	0.00%	0.00%
Municipal Waste	RICE	0.00%	0.00%	0.00%
Municipal Waste	Steam	0.00%	0.04%	0.04%
Oil	CC	0.00%	0.06%	0.06%
Oil	CT	0.78%	1.46%	2.25%
Oil	RICE	0.11%	0.00%	0.11%
Oil	Steam	0.00%	0.03%	0.03%
Other	Solar	0.00%	0.74%	0.74%
Other	Steam	0.00%	0.05%	0.05%
Solar	Solar	0.00%	0.01%	0.01%
Uranium	Steam	0.00%	0.39%	0.39%
Wind	Wind	0.15%	10.97%	11.12%
All Marginal Units		7.76%	92.24%	100.00%

Table 3-69 shows the fuel used and technology where relevant, of marginal resources in the day-ahead energy market. In 2022, up to congestion transactions were 49.0 percent of marginal resources compared to 35.2 percent in 2021. In 2022, virtual transactions were 84.1 percent of marginal resources compared to 80.2 percent in 2021.¹⁰³

¹⁰³ The data for the September 2021 through December 2022 period is from the pricing run.

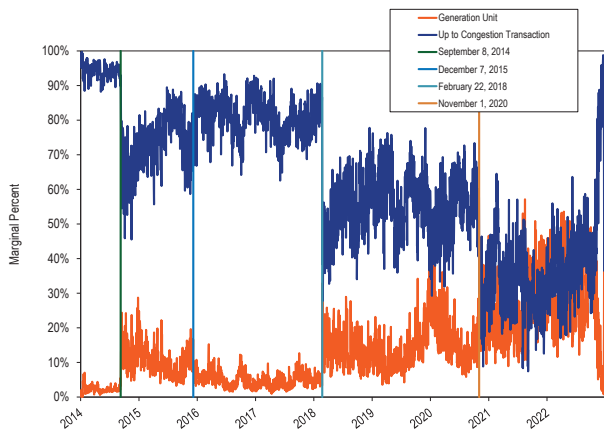
Table 3-69 Day-ahead marginal resources by type/fuel used and technology: 2018 through 2022

Type/Fuel	Technology	2018	2019	2020	2021	2022
Up to Congestion Transaction	NA	62.30%	57.39%	51.34%	35.16%	49.04%
DEC	NA	16.90%	17.04%	18.79%	27.09%	18.77%
INC	NA	9.78%	12.76%	13.24%	17.91%	16.25%
Gas	CC	5.34%	7.42%	9.91%	11.26%	10.05%
Coal	Steam	4.63%	4.45%	5.12%	5.63%	3.19%
Wind	Wind	0.13%	0.10%	0.38%	1.26%	0.96%
Gas	CT	0.20%	0.11%	0.21%	0.39%	0.52%
Gas	Steam	0.28%	0.38%	0.47%	0.54%	0.45%
Dispatchable Transaction	NA	0.13%	0.10%	0.10%	0.27%	0.27%
Oil	CT	0.04%	0.05%	0.10%	0.12%	0.22%
Gas	RICE	0.04%	0.06%	0.05%	0.14%	0.10%
Price Sensitive Demand	NA	0.02%	0.00%	0.00%	0.06%	0.05%
Other	Solar	0.02%	0.01%	0.02%	0.04%	0.05%
Oil	RICE	0.00%	0.00%	0.00%	0.02%	0.03%
Oil	CC	0.02%	0.00%	0.00%	0.00%	0.02%
Oil	Steam	0.04%	0.01%	0.01%	0.02%	0.01%
Water	Hydro	0.00%	0.00%	0.00%	0.00%	0.01%
Other	Steam	0.01%	0.01%	0.04%	0.02%	0.01%
Municipal Waste	RICE	0.01%	0.01%	0.01%	0.03%	0.00%
Uranium	Steam	0.12%	0.10%	0.21%	0.04%	0.00%
Municipal Waste	Steam	0.00%	0.00%	0.00%	0.00%	0.00%
Total		100.00%	100.00%	100.00%	100.00%	100.00%

Figure 3-49 shows, for the day-ahead energy market from January 2014 through December 2022, the daily proportion of marginal resources that were up to congestion transactions or generation units. The UTC share increased from 35.2 percent in 2021 to 49.0 percent in 2022.

Up to congestion transaction volumes decreased following the allocation of uplift charges on November 1, 2020, but increased in 2022.¹⁰⁴ The hourly average submitted up to congestion bid MW increased by 137.4 percent and cleared up to congestion bid MW increased by 87.8 percent in 2022 compared to 2021.

Figure 3-49 Day-ahead marginal up to congestion transaction and generation units: January 2014 through December 2022



¹⁰⁴ 172 FERC ¶ 61,046 (2020).

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 2022. Natural gas prices, coal prices, and oil prices increased in 2022 compared to 2021. The price of natural gas in the Marcellus Shale production area is lower than in other areas of PJM and a number of new combined cycle plants have located in the production area since 2016. In 2022, the price of production gas was 84.6 percent higher than in 2021, the price of eastern natural gas was 103.2 percent higher and the price of western natural gas was 38.4 percent higher. The price of Northern Appalachian coal was 142.9 percent higher; the price of Central Appalachian coal was 123.0 percent higher; and the price of Powder River Basin coal was 8.5 percent higher.¹⁰⁵ In 2022, the price of Northern Appalachian coal was the highest it has been in at least 20 years and the price of Central Appalachian coal was the highest it has been since 2008. The price of ULSD NY Harbor Barge was 91.4 percent higher in 2022 than in 2021.

¹⁰⁵ 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 2022 (\$/MMBtu)

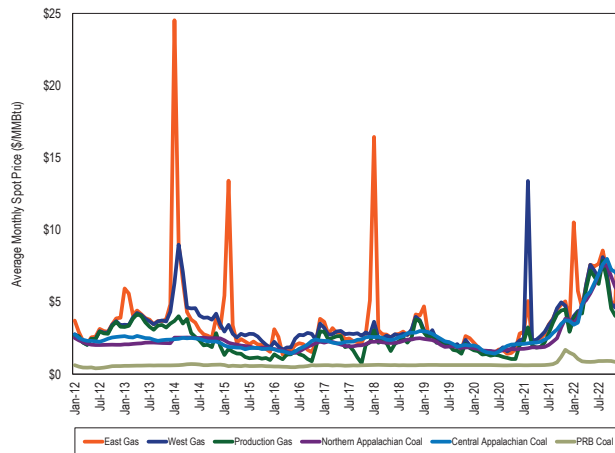


Table 3-70 compares the PJM real-time fuel-cost adjusted load-weighted average LMP in the 2022 to the load-weighted average LMP in 2021.¹⁰⁶ The real-time load-weighted average LMP in 2022 increased by \$40.36 per MWh or 101.4 percent from the real-time load-weighted average LMP in 2021. The real-time load-weighted average LMP for 2022 was 31.8 percent higher than the real-time fuel-cost adjusted load-weighted average LMP for 2022. The real-time fuel-cost adjusted load-weighted average LMP for 2022 was 52.8 percent higher than the real-time load-weighted average LMP for 2021. If fuel and emissions costs in 2022 had been the same as in 2021, holding the market dispatch constant, the real-time load-weighted average LMP in 2022 would have been lower, \$60.80 per MWh, than the observed \$80.14 per MWh.

A significant portion, 47.9 percent, of the increase in real-time load-weighted average LMP, \$19.34 per MWh out of \$40.36 per MWh, is directly attributable to fuel costs. Contributors to the other \$21.01 per MWh are increased load, adjusted dispatch, including adjustments to dispatch due to changes in relative fuel costs among units, emissions costs, and higher markups. The result of holding the 2022 market dispatch constant includes the dispatch of units in 2022 that did not run in 2021 due to very high gas costs.

The fuel-cost adjusted load-weighted average LMP includes fuel costs associated with amortized start up

¹⁰⁶ The fuel-cost adjusted LMP reflects both the fuel and emissions where applicable, including NO_x, CO₂, and SO_x costs.

and no load offers of the marginal fast start units in the pricing run.

Table 3-70 Real-time fuel-cost adjusted load-weighted average LMP (Dollars per MWh): 2021 and 2022

	2022 Fuel-Cost Adjusted Load-Weighted LMP	2022 Load-Weighted LMP	Change	Percent Change
Average	\$60.80	\$80.14	\$19.34	31.8%
	2021 Load-Weighted LMP	2022 Fuel-Cost Adjusted Load-Weighted LMP	Change	Percent Change
Average	\$39.78	\$60.80	\$21.01	52.8%
	2021 Load-Weighted LMP	2022 Load-Weighted LMP	Change	Change
Average	\$39.78	\$80.14	\$40.36	101.4%

Table 3-71 shows the impact of each fuel type on the difference between the fuel-cost adjusted load-weighted average LMP and the load-weighted average LMP in 2022. Table 3-71 shows that higher natural gas prices explain 90.8 percent of the fuel-cost related increase in the real-time annual load-weighted average LMP in 2022 from 2021.

Table 3-71 Share of change in fuel-cost adjusted LMP (\$/MWh) by fuel type: 2022 adjusted to 2021 fuel prices

Fuel Type	Share of Change in Fuel Cost Adjusted Load Weighted LMP	Percent
Gas	\$17.57	90.8%
Coal	\$1.37	7.1%
Oil	\$0.41	2.1%
Other	\$0.00	0.0%
Total	\$19.34	100.0%

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, SO₂ and

CO₂ emission credits, emission rates for NO_x, emission rates for SO₂ and emission rates for CO₂. The CO₂ emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland, New Jersey, and Virginia.¹⁰⁷ The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes the commitment and dispatch of energy and reserves. When generators providing energy have to be dispatched down from their economic operating level to meet reserve requirements, the joint optimization of energy and reserves takes into account the opportunity cost of the reduced generation and the associated incremental cost to maintain reserves. If a unit incurring such opportunity costs is a marginal resource in the energy market, this opportunity cost will contribute to LMP. The component, ancillary service redispatch cost, shows the contribution of this cost to the PJM's load weighted LMP. In addition, in periods when the SCED solution does not meet the reserve requirements, PJM should invoke shortage pricing, but only if there is a well defined operating reserve demand curve. During shortage conditions, the LMPs of marginal generators reflect the cost of not meeting the reserve requirements, the scarcity component, which is defined by the operating reserve demand curve.¹⁰⁸

Starting on September 1, 2021, the components shown in Table 3-72 and Table 3-73 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.¹⁰⁹ Table 3-72 shows that in 2022, 7.1 percent of the load-weighted LMP was the result of coal costs, 51.7 percent was the result of gas costs and 2.2 percent was the result of the cost of carbon emission allowances. Using unadjusted cost-based offers, negative markup was -4.9 percent of the load-weighted LMP. Using unadjusted cost-based offers, positive markup was 9.1 percent of the load weighted LMP. The fuel-related components of LMP reflect the degree to which the cost of the

identified fuel affects LMP and does not reflect the other components of the offers of units burning that fuel. LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no cheaper generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission penalty factors. In 2022, 5.8 percent of the load-weighted LMP was the result of transmission penalty factors affecting LMPs. The percent contribution of transmission penalty factors has increased substantially since PJM removed the constraint relaxation logic and allowed penalty factors to affect LMPs starting in February 2019. The component NA is the unexplained portion of load-weighted LMP. For several intervals, PJM failed to provide all the data needed to accurately calculate generator sensitivity factors. As a result, the LMP for those intervals cannot be decomposed into component costs. The NA component is the cumulative effect of excluding those five minute intervals. The percent column is the difference (in percentage points) in the proportion of LMP represented by each component in 2022 and 2021.

¹⁰⁷ New Jersey withdrew from RGGI, effective January 1, 2012, and rejoined RGGI effective January 1, 2020. Virginia joined RGGI effective January 1, 2021.

¹⁰⁸ Scarcity component includes ancillary service redispatch cost component during periods of scarcity.

¹⁰⁹ These components are explained in the *Technical Reference for PJM Markets*, at p 27 "Calculation and Use of Generator Sensitivity/Unit Participation Factors," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 3-72 Components of real-time (Unadjusted) load-weighted average LMP: 2021 and 2022

Element	2021		2022		Change in Percent
	Contribution to LMP	Percent	Contribution to LMP	Percent	
Gas	\$21.43	53.9%	\$41.42	51.7%	(2.2%)
Positive Markup	\$3.68	9.2%	\$7.29	9.1%	(0.2%)
Coal	\$4.11	10.3%	\$5.66	7.1%	(3.3%)
Scarcity	\$0.22	0.6%	\$5.05	6.3%	5.7%
Ten Percent Adder	\$2.54	6.4%	\$4.70	5.9%	(0.5%)
Transmission Constraint Penalty Factor	\$3.31	8.3%	\$4.63	5.8%	(2.6%)
Market-to-Market	\$0.41	1.0%	\$2.48	3.1%	2.1%
Variable Maintenance	\$1.36	3.4%	\$2.40	3.0%	(0.4%)
NO _x Cost	\$0.19	0.5%	\$2.17	2.7%	2.2%
Emergency Demand Response	\$0.00	0.0%	\$1.75	2.2%	2.2%
CO ₂ Cost	\$1.08	2.7%	\$1.74	2.2%	(0.5%)
Opportunity Cost Adder	\$0.16	0.4%	\$1.58	2.0%	1.6%
Ancillary Service Redispatch Cost	\$0.35	0.9%	\$1.45	1.8%	0.9%
Oil	\$0.25	0.6%	\$1.42	1.8%	1.2%
Variable Operations	\$0.84	2.1%	\$0.94	1.2%	(0.9%)
LPA Rounding Difference	\$0.18	0.5%	\$0.64	0.8%	0.3%
Increase Generation Differential	\$0.13	0.3%	\$0.35	0.4%	0.1%
NA	\$1.51	3.8%	\$0.25	0.3%	(3.5%)
Other	\$0.01	0.0%	\$0.02	0.0%	0.0%
Landfill Gas	\$0.00	0.0%	\$0.02	0.0%	0.0%
SO ₂ Cost	\$0.00	0.0%	\$0.00	0.0%	(0.0%)
LPA-SCED Differential	\$0.07	0.2%	(\$0.03)	(0.0%)	(0.2%)
Decrease Generation Differential	(\$0.03)	(0.1%)	(\$0.04)	(0.1%)	0.0%
Renewable Energy Credits	(\$0.03)	(0.1%)	(\$0.39)	(0.5%)	(0.4%)
PJM Administrative Cap	\$0.00	0.0%	(\$1.39)	(1.7%)	(1.7%)
Negative Markup	(\$1.99)	(5.0%)	(\$3.96)	(4.9%)	0.1%
Total	\$39.78	100.0%	\$80.14	100.0%	0.0%

Components of LMP Increase in 2022

Table 3-74 shows the components of the increase in real-time load-weighted average LMP from 2021 to 2022. In 2022, the real-time load-weighted average LMP increased by \$40.36 per MWh, 101.4 percent. Most of the increase, 56.6 percent of the increase in LMP, was the result of the \$22.82 per MWh increase in the fuel and consumables cost components of LMP (the sum of gas, coal, oil, landfill gas, variable operations). The emissions cost components of LMP (the sum of NO_x, CO₂, opportunity cost adder, SO₂, and renewable energy credits) increased the LMP by \$3.71 per MWh, 9.2 percent of the increase in LMP, primarily as a result of the high NO_x allowance prices during the summer. The sum of the positive and negative markups, ten percent adder, and maintenance cost components, all of which reflect market power, increased the LMP \$4.83 per MWh, 12.0 percent of the increase in LMP. The emergency demand response called on by PJM during Elliott increased the LMP by \$1.75 per MWh, 4.3 percent of the increase in LMP. The scarcity component, primarily a result of shortage pricing during Elliott increased the LMP by \$4.83 per MWh, 12.0 percent of the increase in the LMP. The LMP increase would have been higher if PJM had not imposed a \$3,700.00 per MWh administrative cap. The administrative cap reduced the LMP by \$1.39 per MWh, a 3.5 percent decrease. The transmission constraint penalty factor increased the LMP by \$1.31 per MWh, 3.2 percent. The ancillary service redispatch cost, the opportunity cost of reduced marginal generation to meet reserve requirements, increased the LMP by \$1.11 per MWh, 2.7 percent.

In order to understand the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach (Table 3-72 and Table 3-77) markup is the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-73 and Table 3-78), the 10 percent markup is removed from the cost-based offers of coal, gas, and oil units (adjusted markup).

The components of LMP are shown in Table 3-73, including markup using adjusted cost-based offers.

Table 3-73 Components of real-time (Adjusted) load-weighted average LMP: 2021 and 2022

Element	2021		2022		Change in Percent
	Contribution to LMP	Percent	Contribution to LMP	Percent	
Gas	\$21.43	53.9%	\$41.42	51.7%	(2.2%)
Positive Markup	\$5.12	12.9%	\$10.02	12.5%	(0.4%)
Coal	\$4.11	10.3%	\$5.66	7.1%	(3.3%)
Scarcity	\$0.22	0.6%	\$5.05	6.3%	5.7%
Transmission Constraint Penalty Factor	\$3.31	8.3%	\$4.63	5.8%	(2.6%)
Market-to-Market	\$0.41	1.0%	\$2.48	3.1%	2.1%
Variable Maintenance	\$1.36	3.4%	\$2.40	3.0%	(0.4%)
NO _x Cost	\$0.19	0.5%	\$2.17	2.7%	2.2%
Emergency Demand Response	\$0.00	0.0%	\$1.75	2.2%	2.2%
CO ₂ Cost	\$1.08	2.7%	\$1.74	2.2%	(0.5%)
Opportunity Cost Adder	\$0.16	0.4%	\$1.58	2.0%	1.6%
Ancillary Service Redispatch Cost	\$0.35	0.9%	\$1.45	1.8%	0.9%
Oil	\$0.25	0.6%	\$1.42	1.8%	1.2%
Variable Operations	\$0.84	2.1%	\$0.94	1.2%	(0.9%)
LPA Rounding Difference	\$0.18	0.5%	\$0.64	0.8%	0.3%
Increase Generation Differential	\$0.13	0.3%	\$0.35	0.4%	0.1%
NA	\$1.51	3.8%	\$0.25	0.3%	(3.5%)
Other	\$0.01	0.0%	\$0.02	0.0%	0.0%
Landfill Gas	\$0.00	0.0%	\$0.02	0.0%	0.0%
Ten Percent Adder	\$0.00	0.0%	\$0.00	0.0%	0.0%
SO ₂ Cost	\$0.00	0.0%	\$0.00	0.0%	(0.0%)
LPA-SCED Differential	\$0.07	0.2%	(\$0.03)	(0.0%)	(0.2%)
Decrease Generation Differential	(\$0.03)	(0.1%)	(\$0.04)	(0.1%)	0.0%
Renewable Energy Credits	(\$0.03)	(0.1%)	(\$0.39)	(0.5%)	(0.4%)
PJM Administrative Cap	\$0.00	0.0%	(\$1.39)	(1.7%)	(1.7%)
Negative Markup	(\$0.89)	(2.2%)	(\$2.00)	(2.5%)	(0.3%)
Total	\$39.78	100.0%	\$80.14	100.0%	0.0%

PJM implemented fast start pricing on September 1, 2021. The commitment cost related components of LMP are shown in Table 3-74, including markup using unadjusted cost-based offers for 2022. In 2022, 2.8 percent of the load-weighted average LMP was the result of commitment costs. The majority of the commitment costs in LMP were fuel costs in the no load component of offers for gas fired fast start units. The second largest component was maintenance costs.

Table 3-74 Components of Increase in real-time load-weighted average LMP: 2022

Component	Increase in			
	2021	2022	LMP	Percent
Fuel and Consumables	\$26.62	\$49.45	\$22.82	56.6%
Emission Related	\$1.40	\$5.11	\$3.71	9.2%
Market Power Related	\$5.59	\$10.42	\$4.83	12.0%
Scarcity	\$0.22	\$5.05	\$4.83	12.0%
Transmission Constraint Penalty Factor	\$3.31	\$4.63	\$1.31	3.2%
Ancillary Service Redispatch Cost	\$0.35	\$1.45	\$1.11	2.7%
Emergency Demand Response	\$0.00	\$1.75	\$1.75	4.3%
PJM Administrative Cap	\$0.00	(\$1.39)	(\$1.39)	(3.5%)
All Other	\$2.28	\$3.67	\$1.39	3.4%
Total	\$39.78	\$80.14	\$40.36	100.0%

Table 3-75 Commitment cost related components of real-time (Unadjusted) load-weighted average LMP: 2022

Element	Start Cost Components		No Load Components		Other Components		Total	
	Contribution		Contribution		Contribution		Contribution	
	to LMP	Percent	to LMP	Percent	to LMP	Percent	to LMP	Percent
Gas	\$0.00	0.0%	\$1.45	1.8%	\$39.97	49.9%	\$41.42	51.7%
Positive Markup	\$0.08	0.1%	\$0.00	0.0%	\$7.20	9.0%	\$7.29	9.1%
Coal	\$0.00	0.0%	\$0.00	0.0%	\$5.66	7.1%	\$5.66	7.1%
Scarcity	\$0.00	0.0%	\$0.00	0.0%	\$5.05	6.3%	\$5.05	6.3%
Ten Percent Adder	\$0.04	0.1%	\$0.14	0.2%	\$4.52	5.6%	\$4.70	5.9%
Transmission Constraint Penalty Factor	\$0.00	0.0%	\$0.00	0.0%	\$4.63	5.8%	\$4.63	5.8%
Market-to-Market	\$0.00	0.0%	\$0.00	0.0%	\$2.48	3.1%	\$2.48	3.1%
Variable Maintenance	\$0.47	0.6%	\$0.03	0.0%	\$1.90	2.4%	\$2.40	3.0%
NO _x Cost	\$0.02	0.0%	\$0.13	0.2%	\$2.02	2.5%	\$2.17	2.7%
Emergency Demand Response	\$0.00	0.0%	\$0.00	0.0%	\$1.75	2.2%	\$1.75	2.2%
CO ₂ Cost	\$0.00	0.0%	\$0.02	0.0%	\$1.72	2.1%	\$1.74	2.2%
Opportunity Cost Adder	\$0.00	0.0%	\$0.00	0.0%	\$1.58	2.0%	\$1.58	2.0%
Ancillary Service Redispatch Cost	\$0.00	0.0%	\$0.00	0.0%	\$1.45	1.8%	\$1.45	1.8%
Oil	\$0.00	0.0%	\$0.13	0.2%	\$1.28	1.6%	\$1.42	1.8%
Variable Operations	\$0.00	0.0%	\$0.00	0.0%	\$0.94	1.2%	\$0.94	1.2%
LPA Rounding Difference	\$0.00	0.0%	\$0.00	0.0%	\$0.64	0.8%	\$0.64	0.8%
Increase Generation Differential	\$0.00	0.0%	\$0.00	0.0%	\$0.35	0.4%	\$0.35	0.4%
NA	\$0.00	0.0%	\$0.00	0.0%	\$0.25	0.3%	\$0.25	0.3%
Other	\$0.00	0.0%	\$0.00	0.0%	\$0.02	0.0%	\$0.02	0.0%
Landfill Gas	\$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%	(\$0.03)	(0.0%)	(\$0.03)	(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%	(\$0.39)	(0.5%)	(\$0.39)	(0.5%)
PJM Administrative Cap	\$0.00	0.0%	\$0.00	0.0%	(\$1.39)	(1.7%)	(\$1.39)	(1.7%)
Negative Markup	(\$0.19)	(0.2%)	(\$0.06)	(0.1%)	(\$3.71)	(4.6%)	(\$3.96)	(4.9%)
Total	\$0.43	0.5%	\$1.84	2.3%	\$77.87	97.2%	\$80.14	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 2022.

Table 3-76 Comparison of components of real-time (Unadjusted) load-weighted average LMP in the dispatch run and pricing run: 2022

Element	Dispatch		Pricing		Change in Percent
	Contribution to LMP	Percent	Contribution to LMP	Percent	
Gas	\$38.90	51.0%	\$41.42	51.7%	0.7%
Positive Markup	\$6.97	9.1%	\$7.29	9.1%	(0.0%)
Coal	\$6.05	7.9%	\$5.66	7.1%	(0.9%)
Scarcity	\$4.61	6.0%	\$5.05	6.3%	0.3%
Ten Percent Adder	\$4.31	5.6%	\$4.70	5.9%	0.2%
Transmission Constraint Penalty Factor	\$4.94	6.5%	\$4.63	5.8%	(0.7%)
Market-to-Market	\$2.72	3.6%	\$2.48	3.1%	(0.5%)
Variable Maintenance	\$1.64	2.1%	\$2.40	3.0%	0.8%
NO _x Cost	\$1.83	2.4%	\$2.17	2.7%	0.3%
Emergency Demand Response	\$1.79	2.3%	\$1.75	2.2%	(0.2%)
CO ₂ Cost	\$1.77	2.3%	\$1.74	2.2%	(0.1%)
Opportunity Cost Adder	\$1.03	1.3%	\$1.58	2.0%	0.6%
Ancillary Service Redispatch Cost	\$1.19	1.6%	\$1.45	1.8%	0.2%
Oil	\$0.73	1.0%	\$1.42	1.8%	0.8%
Variable Operations	\$0.84	1.1%	\$0.94	1.2%	0.1%
LPA Rounding Difference	\$0.51	0.7%	\$0.64	0.8%	0.1%
Increase Generation Differential	\$0.22	0.3%	\$0.35	0.4%	0.2%
NA	\$0.17	0.2%	\$0.25	0.3%	0.1%
Other	\$0.02	0.0%	\$0.02	0.0%	(0.0%)
Landfill Gas	(\$0.03)	(0.0%)	\$0.02	0.0%	0.1%
SO ₂ Cost	\$0.00	0.0%	\$0.00	0.0%	(0.0%)
LPA-SCED Differential	(\$0.03)	(0.0%)	(\$0.03)	(0.0%)	(0.0%)
Decrease Generation Differential	(\$0.01)	(0.0%)	(\$0.04)	(0.1%)	(0.0%)
Renewable Energy Credits	(\$0.38)	(0.5%)	(\$0.39)	(0.5%)	0.0%
PJM Administrative Cap	\$0.00	0.0%	(\$1.39)	(1.7%)	(1.7%)
Negative Markup	(\$3.44)	(4.5%)	(\$3.96)	(4.9%)	(0.4%)
Total	\$76.34	100.0%	\$80.14	100.0%	0.0%

Components of Day-Ahead Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. For physical units, those offers can be decomposed into their components including fuel costs, emission costs, variable operation and maintenance costs, markup, and the 10 percent cost offer adder. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the day-ahead energy market with an offer price that cannot be decomposed. Using identified marginal resource offers and the components of unit offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

PJM implemented fast start pricing on September 1, 2021, in the day-ahead market as well. The marginal resources and sensitivity factors are different between the dispatch run and pricing run. Since PJM uses LMPs generated in the pricing run as settlement LMPs, in Table 3-77 and Table 3-78, the components of day-ahead load-weighted average LMP in September 2021 through December 2022 are calculated using marginal resource and sensitivity factor data from the pricing run, and original data is used in the first eight months of 2021.

Table 3-77 shows the components of the PJM day-ahead annual load-weighted average LMP. In 2022, 23.0 percent of the load-weighted LMP was the result of gas costs, 8.4 percent of the load-weighted LMP was the result of coal costs, 15.9 percent was the result of DECs, 26.2 percent was the result of INCs, 7.8 percent was the result of UTCs and 7.3 percent was the result of positive markup.¹¹⁰

Table 3-77 Components of day-ahead (Unadjusted) load-weighted average LMP (Dollars per MWh): 2021 and 2022

Element	2021		2022		Change in Percent
	Contribution to LMP	Percent	Contribution to LMP	Percent	
INC	\$6.76	17.2%	\$19.80	26.2%	9.1%
Gas	\$10.21	25.9%	\$17.35	23.0%	(2.9%)
DEC	\$11.70	29.7%	\$11.99	15.9%	(13.8%)
Coal	\$4.42	11.2%	\$6.34	8.4%	(2.8%)
Up to Congestion Transaction	\$0.32	0.8%	\$5.91	7.8%	7.0%
Positive Markup	\$2.24	5.7%	\$5.54	7.3%	1.6%
Ten Percent Adder	\$1.51	3.8%	\$2.73	3.6%	(0.2%)
Dispatchable Transaction	\$0.58	1.5%	\$2.43	3.2%	1.7%
Variable Maintenance	\$0.78	2.0%	\$2.09	2.8%	0.8%
CO ₂ Cost	\$0.77	2.0%	\$1.42	1.9%	(0.1%)
NO _x Cost	\$0.19	0.5%	\$1.03	1.4%	0.9%
Variable Operations	\$0.65	1.7%	\$0.49	0.6%	(1.0%)
Price Sensitive Demand	\$0.17	0.4%	\$0.29	0.4%	(0.1%)
Municipal Waste	\$0.01	0.0%	\$0.01	0.0%	(0.0%)
Other	\$0.00	0.0%	\$0.01	0.0%	0.0%
SO ₂ Cost	\$0.00	0.0%	\$0.00	0.0%	(0.0%)
Station Service Charges	\$0.00	0.0%	\$0.00	0.0%	0.0%
Uranium	\$0.00	0.0%	\$0.00	0.0%	(0.0%)
Opportunity Cost Adder	\$0.01	0.0%	(\$0.00)	(0.0%)	(0.0%)
Wind	(\$0.13)	(0.3%)	(\$0.14)	(0.2%)	0.1%
Negative Markup	(\$1.02)	(2.6%)	(\$1.07)	(1.4%)	1.2%
Oil	\$0.19	0.5%	(\$1.75)	(2.3%)	(2.8%)
NA	\$0.01	0.0%	\$0.96	1.3%	1.2%
Total	\$39.37	100.0%	\$75.44	100.0%	0.0%

Table 3-78 shows the components of the PJM day-ahead annual load-weighted average LMP including the adjusted markup calculated by excluding the 10 percent adder from the coal, gas or oil units.

¹¹⁰ May 21, 2022 HE 1700 (EPT), September 15, 2022 HE 0200 (EPT), September 21, 2022 HE 1500 (EPT), October 24, 2022, HE 0900 (EPT), and November 11, 2022, HE 0700 (EPT) had abnormal unit participant factor (UPF) values and the marginal resources data in that hour was removed from 2022 pricing run data for the calculations here.

Table 3-78 Components of day-ahead (Adjusted) load-weighted average LMP (Dollars per MWh): 2021 and 2022

Element	2021		2022		Change in Percent
	Contribution to LMP	Percent	Contribution to LMP	Percent	
INC	\$6.76	17.2%	\$19.80	26.2%	9.1%
Gas	\$10.06	25.5%	\$17.48	23.2%	(2.4%)
DEC	\$11.70	29.7%	\$11.99	15.9%	(13.8%)
Positive Markup	\$3.37	8.5%	\$7.78	10.3%	1.8%
Coal	\$4.40	11.2%	\$6.30	8.4%	(2.8%)
Up to Congestion Transaction	\$0.32	0.8%	\$5.91	7.8%	7.0%
Dispatchable Transaction	\$0.58	1.5%	\$2.43	3.2%	1.7%
Variable Maintenance	\$0.77	2.0%	\$2.09	2.8%	0.8%
CO ₂ Cost	\$0.77	2.0%	\$1.40	1.9%	(0.1%)
NO _x Cost	\$0.19	0.5%	\$1.02	1.4%	0.9%
Variable Operations	\$0.65	1.7%	\$0.48	0.6%	(1.0%)
Price Sensitive Demand	\$0.17	0.4%	\$0.29	0.4%	(0.1%)
Municipal Waste	\$0.01	0.0%	\$0.01	0.0%	(0.0%)
Other	\$0.00	0.0%	\$0.01	0.0%	0.0%
Station Service Charges	\$0.00	0.0%	\$0.00	0.0%	0.0%
SO ₂ Cost	\$0.00	0.0%	\$0.00	0.0%	(0.0%)
Uranium	\$0.00	0.0%	\$0.00	0.0%	(0.0%)
Opportunity Cost Adder	\$0.01	0.0%	(\$0.00)	(0.0%)	(0.0%)
Ten Percent Adder	(\$0.01)	(0.0%)	(\$0.01)	(0.0%)	0.0%
Wind	(\$0.13)	(0.3%)	(\$0.14)	(0.2%)	0.1%
Negative Markup	(\$0.44)	(1.1%)	(\$0.61)	(0.8%)	0.3%
Oil	\$0.19	0.5%	(\$1.74)	(2.3%)	(2.8%)
NA	\$0.01	0.0%	\$0.95	1.3%	1.2%
Total	\$39.37	100.0%	\$75.44	100.0%	0.0%

Table 3-79 shows the components of increase in day-ahead load-weighted average LMP from 2021 to 2022. In 2022, the day-ahead load-weighted average LMP increased by \$36.07 per MWh, 91.6 percent, compared to 2021. Most of the increase is due to the \$13.03 per MWh increase in INC component of LMP and contributed 36.1 percent of the increase in LMP. The second most of the increase is due to the \$7.12 per MWh increase in fuel and consumables cost components of LMP (the sum of gas, coal, oil, and landfill gas) and contributed 19.7 percent of the increase in LMP.

Table 3-79 Components of Increase in day-ahead load-weighted average LMP: 2022

Element	2021	2022	Increase	
			in LMP	Percent
INC	\$6.76	\$19.80	\$13.03	36.1%
Fuel	\$14.69	\$21.81	\$7.12	19.7%
Up to Congestion Transaction	\$0.32	\$5.91	\$5.59	15.5%
Markup	\$1.22	\$4.47	\$3.25	9.0%
Dispatchable Transaction	\$0.58	\$2.43	\$1.85	5.1%
Emissions	\$0.96	\$2.46	\$1.50	4.1%
Ten Percent Adder	\$1.51	\$2.73	\$1.23	3.4%
Variable Maintenance and Operations	\$1.43	\$2.58	\$1.15	3.2%
Other	\$0.20	\$1.26	\$1.07	3.0%
DEC	\$11.70	\$11.99	\$0.29	0.8%
Total	\$39.37	\$75.44	\$36.07	100.0%

PJM implemented fast start pricing on September 1, 2021, and amortized startup cost and no load cost were included in the price offers of fast start marginal units. The commitment cost related components of LMP reflect the amortized startup cost and no load cost of the fast start marginal units. Table 3-80 shows that in 2022, 0.6 percent of the load-weighted average LMP was the result of commitment costs using unadjusted cost-based offers.

Table 3-80 Commitment cost related components of day-ahead (Unadjusted) load-weighted average LMP: 2022

Element	Commitment		Other		All Generation		Virtuals and Transactions		Total	
	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent
INC	\$0.00	0.0%	\$0.00	0.0%	\$0.00	0.0%	\$19.80	26.2%	\$19.80	26.2%
Gas	\$0.34	0.5%	\$17.01	22.5%	\$17.35	23.0%	\$0.00	0.0%	\$17.35	23.0%
DEC	\$0.00	0.0%	\$0.00	0.0%	\$0.00	0.0%	\$11.99	15.9%	\$11.99	15.9%
Coal	\$0.00	0.0%	\$6.34	8.4%	\$6.34	8.4%	\$0.00	0.0%	\$6.34	8.4%
Up to Congestion Transaction	\$0.00	0.0%	\$0.00	0.0%	\$0.00	0.0%	\$5.91	7.8%	\$5.91	7.8%
Positive Markup	\$0.00	0.0%	\$5.53	7.3%	\$5.54	7.3%	\$0.00	0.0%	\$5.54	7.3%
Ten Percent Adder	\$0.04	0.1%	\$2.69	3.6%	\$2.73	3.6%	\$0.00	0.0%	\$2.73	3.6%
Dispatchable Transaction	\$0.00	0.0%	\$0.00	0.0%	\$0.00	0.0%	\$2.43	3.2%	\$2.43	3.2%
NO _x Cost	\$0.02	0.0%	\$2.07	2.8%	\$2.09	2.8%	\$0.00	0.0%	\$2.09	2.8%
CO ₂ Cost	\$0.03	0.0%	\$1.39	1.8%	\$1.42	1.9%	\$0.00	0.0%	\$1.42	1.9%
NO ₂	\$0.02	0.0%	\$1.01	1.3%	\$1.03	1.4%	\$0.00	0.0%	\$1.03	1.4%
Variable Operations	\$0.00	0.0%	\$0.49	0.6%	\$0.49	0.6%	\$0.00	0.0%	\$0.49	0.6%
Price Sensitive Demand	\$0.00	0.0%	\$0.00	0.0%	\$0.00	0.0%	\$0.29	0.4%	\$0.29	0.4%
Municipal Waste	\$0.00	0.0%	\$0.01	0.0%	\$0.01	0.0%	\$0.00	0.0%	\$0.01	0.0%
Other	\$0.00	0.0%	\$0.01	0.0%	\$0.01	0.0%	\$0.00	0.0%	\$0.01	0.0%
SO ₂	\$0.00	0.0%	\$0.00	0.0%	\$0.00	0.0%	\$0.00	0.0%	\$0.00	0.0%
Station Service Charges	\$0.00	0.0%	\$0.00	0.0%	\$0.00	0.0%	\$0.00	0.0%	\$0.00	0.0%
Uranium	\$0.00	0.0%	\$0.00	0.0%	\$0.00	0.0%	\$0.00	0.0%	\$0.00	0.0%
SO ₂ Cost	\$0.00	0.0%	(\$0.00)	(0.0%)	(\$0.00)	(0.0%)	\$0.00	0.0%	(\$0.00)	(0.0%)
Wind	\$0.00	0.0%	(\$0.14)	(0.2%)	(\$0.14)	(0.2%)	\$0.00	0.0%	(\$0.14)	(0.2%)
Negative Markup	(\$0.01)	(0.0%)	(\$1.06)	(1.4%)	(\$1.07)	(1.4%)	\$0.00	0.0%	(\$1.07)	(1.4%)
Oil	\$0.00	0.0%	(\$1.75)	(2.3%)	(\$1.75)	(2.3%)	\$0.00	0.0%	(\$1.75)	(2.3%)
NA	\$0.00	0.0%	\$0.00	0.0%	\$0.96	1.3%	\$0.00	0.0%	\$0.96	1.3%
Total	\$0.45	0.6%	\$33.62	44.6%	\$35.02	46.4%	\$40.42	53.6%	\$75.44	100.0%

Table 3-81 compares the components of LMP between the dispatch run and the pricing run for 2022. The marginal resources and sensitivity factors are different between the dispatch run and pricing run. The dispatch run components of day-ahead load-weighted average LMP are calculated using the marginal resources and sensitivity factors from the dispatch run result and the pricing run components of day-ahead, load-weighted, average LMP are calculated using the marginal resources and sensitivity factors from the pricing run result. The marginal DEC contribution of day-ahead load-weighted LMP decreased by 14.7 percent, the marginal gas generation unit contribution of day-ahead load-weighted average LMP increased by 1.9 percent, the marginal INC contribution of day-ahead load-weighted average LMP increased by 5.0 percent from the dispatch run to the pricing run.

Table 3-81 Components of day-ahead (Unadjusted) load-weighted average LMP in the dispatch run and pricing run: 2022

Element	Dispatch Run		Pricing Run		Change in Percent
	Contribution to LMP	Percent	Contribution to LMP	Percent	
INC	\$16.00	21.2%	\$19.80	26.2%	5.0%
Gas	\$15.90	21.1%	\$17.35	23.0%	1.9%
DEC	\$23.04	30.6%	\$11.99	15.9%	(14.7%)
Coal	\$6.55	8.7%	\$6.34	8.4%	(0.3%)
Up to Congestion Transaction	\$2.50	3.3%	\$5.91	7.8%	4.5%
Positive Markup	\$5.16	6.9%	\$5.54	7.3%	0.5%
Ten Percent Adder	\$2.08	2.8%	\$2.73	3.6%	0.9%
Dispatchable Transaction	\$1.06	1.4%	\$2.43	3.2%	1.8%
Variable Maintenance	\$0.70	0.9%	\$2.09	2.8%	1.8%
CO ₂ Cost	\$0.96	1.3%	\$1.42	1.9%	0.6%
NO _x Cost	\$1.10	1.5%	\$1.03	1.4%	(0.1%)
Variable Operations	\$0.64	0.9%	\$0.49	0.6%	(0.2%)
Price Sensitive Demand	\$0.38	0.5%	\$0.29	0.4%	(0.1%)
Municipal Waste	(\$0.02)	(0.0%)	\$0.01	0.0%	0.0%
Other	\$0.00	0.0%	\$0.01	0.0%	0.0%
SO ₂ Cost	\$0.00	0.0%	\$0.00	0.0%	0.0%
Station Service Charges	\$0.00	0.0%	\$0.00	0.0%	0.0%
Uranium	\$0.00	0.0%	\$0.00	0.0%	(0.0%)
Opportunity Cost Adder	\$0.08	0.1%	(\$0.00)	(0.0%)	(0.1%)
Wind	(\$0.16)	(0.2%)	(\$0.14)	(0.2%)	0.0%
Negative Markup	(\$1.33)	(1.8%)	(\$1.07)	(1.4%)	0.4%
Oil	\$0.69	0.9%	(\$1.75)	(2.3%)	(3.2%)
NA	\$0.00	0.0%	\$0.96	1.3%	1.3%
Total	\$75.35	100.0%	\$75.44	100.0%	0.0%

Shortage

PJM’s energy market experienced five minute shortage pricing for 270 five minute intervals on 22 days in 2022. PJM implemented fast start pricing on September 1, 2021. In 2022, there were 270 five minute intervals with shortage pricing in the pricing run, and 260 intervals with shortage in the dispatch run. Table 3-82 shows a summary of the number of days of the emergency alerts, warnings and actions that were declared in PJM in 2021 and 2022. In 2022, there were six days with emergency actions that triggered Performance Assessment Intervals (PAI). Three of the days with shortage pricing, January 27, December 23, and December 24, 2022, had a cold weather alert in effect. June 13, 2022, with several intervals of shortage, preceded the multiple emergency actions and alerts that began on June 14, 2022.

Table 3-82 Summary of emergency events declared: 2021 and 2022

Event Type	Number of days events declared	
	2021	2022
Cold Weather Alert	6	11
Hot Weather Alert	23	31
Maximum Emergency Generation Alert	0	3
Primary Reserve Alert	0	0
Voltage Reduction Alert	0	1
Primary Reserve Warning	0	0
Voltage Reduction Warning	0	1
Pre Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time)	0	7
Emergency Mandatory Load Management Reduction Action	0	8
Maximum Emergency Action	0	2
Emergency Energy Bids Requested	0	1
Voltage Reduction Action	0	0
Shortage Pricing	14	22
Energy export recalls from PJM capacity resources	0	0

Figure 3-51 shows the number of days that weather and capacity emergency alerts were issued in PJM in 2013 through 2022.

Figure 3-51 Declared emergency alerts: 2013 through 2022

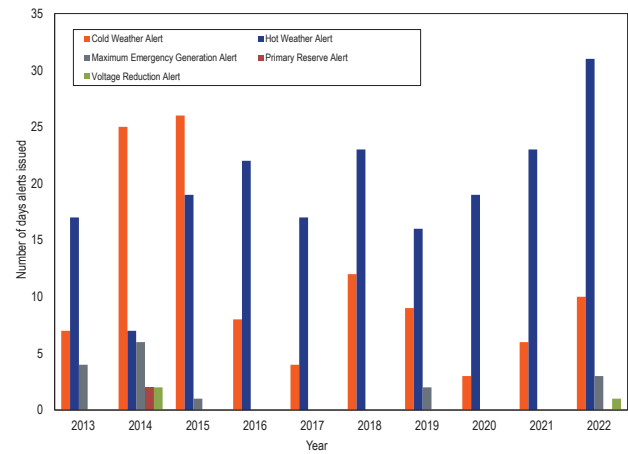
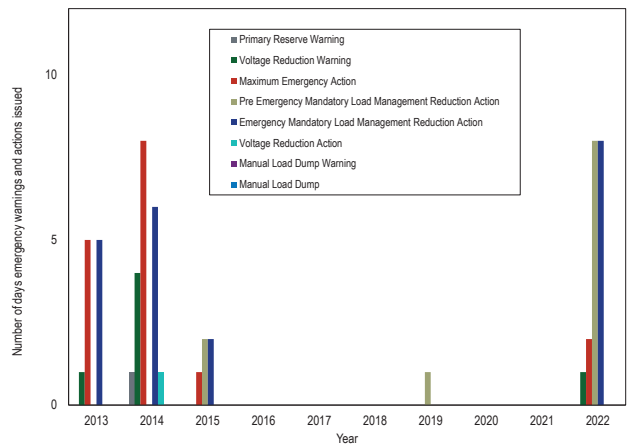


Figure 3-52 shows the number of days that emergency warnings and actions were declared in PJM from 2013 through 2022.

Figure 3-52 Declared emergency warnings and actions: 2013 through 2022



Emergency Procedures

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

Table 3-83 provides a description of PJM declared emergency procedures.^{111 112 113 114}

Table 3-83 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.

111 See PJM. "Manual 13: Emergency Operations," Rev. 85 (Oct. 1, 2022), Section 3.3 Cold Weather Alert.

112 See PJM. "Manual 13: Emergency Operations," Rev. 85 (Oct. 1, 2022), Section 3.4 Hot Weather Alert.

113 See PJM. "Manual 13: Emergency Operations," Rev. 85 (Oct. 1, 2022), Section 2.3.1 Advanced Notice Emergency Procedures: Alerts.

114 See PJM. "Manual 13: Emergency Operations," Rev. 85 (Oct. 1, 2022), Section 2.3.2 Real-Time Emergency Procedures (Warnings and Actions).

Table 3-84 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in 2022.

Table 3-84 Declared emergency alerts, warnings and actions: 2022

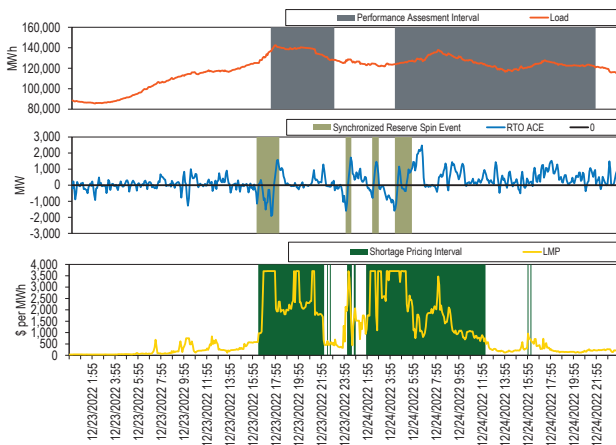
Date	Cold Weather Alert	Hot Weather Alert	Maximum Emergency Generation Alert	Primary Reserve Alert	Voltage Reduction Alert	Primary Reserve Warning	Voltage Reduction Warning and Reduction of Non-Critical Plant Load	Maximum Emergency Generation Action	Pre-Emergency Mandatory Load Management Reduction	Emergency Mandatory Load Management Reduction	Voltage Reduction	Manual Load Dump Warning	Manual Load Dump Action	Load Shed Directive
01/07/2022	COMED													
01/11/2022	Western													
01/21/2022	PJM RTO													
01/25/2022	COMED													
01/26/2022	Western													
01/27/2022	Western													
01/29/2022	Western													
05/20/2022		Mid-Atlantic, Southern												
05/21/2022		Mid-Atlantic, Southern												
05/31/2022		PJM RTO												
06/01/2022		Mid-Atlantic, Southern												
06/13/2022		EKPC												
06/14/2022		Western	AEP						AEP_MARION	AEP_MARION				AEP
06/15/2022		Western							AEP_MARION	AEP_MARION				AEP
06/16/2022		Western							AEP_MARION	AEP_MARION				
06/17/2022		Mid-Atlantic, Southern												
06/20/2022		COMED												
06/21/2022		Western												
06/22/2022		Western												
06/30/2022		PJM RTO												
07/01/2022		Western sans COMED												
07/05/2022		Western												
07/12/2022		Mid-Atlantic												
07/19/2022		Mid-Atlantic												
07/20/2022		PJM RTO												
07/21/2022		PJM RTO												
07/22/2022		PJM RTO												
07/23/2022		PJM RTO												
07/24/2022		PJM RTO												
07/28/2022		Mid-Atlantic, Southern												
08/02/2022		Mid-Atlantic, Southern												
08/03/2022		PJM RTO												
08/04/2022		Mid-Atlantic, Southern												
08/05/2022		Mid-Atlantic												
08/08/2022		Mid-Atlantic												
08/09/2022		Mid-Atlantic, Southern												
08/29/2022		Mid-Atlantic, Southern												
09/19/2022		Mid-Atlantic, Southern												
10/26/2022														
12/23/2022	Western		PJM RTO					PJM RTO	Mid-Atlantic except SMECo, SRE, and UGI; Southern; Western except AMPT, CPP, ITCI, OVEC, and WVPAT	AEP, BGE, COMED, DAY, DEOK, DOM, DPL, DUQ, EKPC, FE-AP, FE-ATSI, FE-JC, FE-PN, PECO, PEPCO				
12/24/2022	PJM RTO		PJM RTO		PJM RTO		PJM RTO	PJM RTO	Mid-Atlantic except SMECo, SRE, and UGI; Southern; Western except AMPT, CPP, ITCI, OVEC, and WVPAT	AEP, BGE, COMED, DAY, DEOK, DOM, DPL, DUQ, EKPC, FE-AP, FE-ATSI, FE-JC, FE-PN, PECO, PEPCO, PPL				
12/25/2022	PJM RTO, Western		PJM RTO					PJM RTO						
12/26/2022	Western													

Winter Storm Elliott

Winter Storm Elliott (Elliott) occurred on December 23 through 26, 2022, in the PJM region. The unanticipated high load and rapid load increase combined with generation outages due to cold weather and fuel issues resulted in Performance Assessment Intervals (PAIs) on December 23 and 24.

Figure 3-54 Figure 3-53 shows the five minute real-time load with PAIs, Area Control Error (ACE) with synchronized reserve events, and load weighted average LMP with shortage pricing intervals for December 23 and 24, 2022. The PAIs were triggered by the dispatch of emergency and pre-emergency demand response resources as well as the maximum generation alert. PJM initiated synchronized reserve events due to low ACE and unit trips. The PJM load weighted average LMP reached the system marginal price cap of \$3,700 per MWh as the result of shortage pricing, transmission constraint penalty factors, and the demand response strike price.

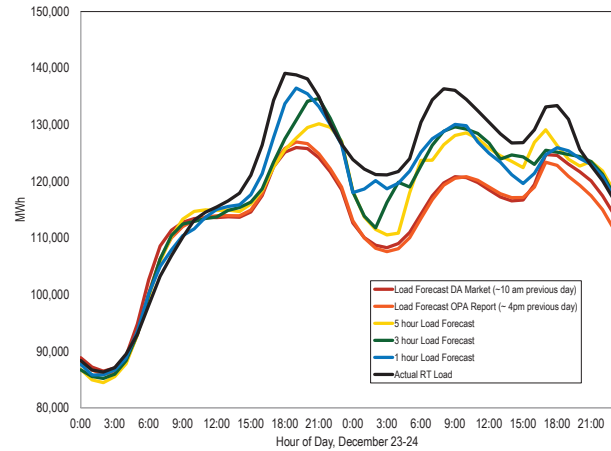
Figure 3-53 Load, Area Control Error, and LMP: December 23 and 24, 2022



Load Forecast

Load exceeded PJM forecasts for the evening of December 23 and the morning of December 24. At the evening peak of December 23, the actual hourly load was 139,090 MW while the day-ahead load forecast was 125,149 MW, an error of 13,940.6 MW, 10.0 percent.

Figure 3-54 Load Forecast vs. Actual Load (MWh): December 23 and 24, 2022



Interchange Volume

PJM was a net exporter of energy in all but three hours during Winter Storm Elliott. The average hourly net scheduled interchange was -3,905 MW. PJM provided exports both to neighboring balancing areas that were shedding load and to neighboring balancing areas with less severe conditions than PJM. Further details are provided in Section 9: Interchange Transactions.

Outages

Extreme cold weather on December 23 and 24, 2022 resulted in very high forced outages in PJM. The highest level of outages occurred on December 24, 2022 at 0500 EPT. Table 3-85 shows the total outages at the start of December 23 and at 0500 EPT on December 24, with a 192 percent increase in outage MW during the event. The outages are categorized by type (e.g. planned, forced, maintenance) and by type of forced outage (e.g. gas supply/transportation issues, gas pressure issues, frozen equipment and emission compliance related).

Table 3-85 Outages on December 23 and 24, 2022

Outage Type/Category	Dec 23 at	Dec 24 at	Difference	
	00:00	05:00	Difference	Percent
Planned Outages	3,308	3,828	520	1.6%
Maintenance Outages	1,712	1,139	(573)	(1.8%)
Gas Supply/Transportation	537	11,585	11,048	34.9%
Cold Weather Related Equipment Failure	355	8,056	7,701	24.3%
Other Forced Outages	10,505	23,472	12,968	41.0%
Total	16,417	48,080	31,663	100%

At the start of December 23, PJM had 16,434 MW (8.8 percent of ICAP) unavailable due to outages. That alone is 3.7 percentage points higher than the assumed 5.08 percent pool wide average EFORd assumed for the 2022/2023 Delivery Year. This means that PJM entered Elliott with more generation on outage than PJM plans for when it procures capacity three years in advance.

Outages increased during the morning of December 23 and increased further after midday. The increase was mainly a result of equipment failure, at 0500 EPT on December 24, 12,925 MW of outages were caused by equipment failure not explicitly associated with the cold weather, categorized as Other Forced Outages. Lack of natural gas or transportation interruption was the second category, accounting for 11,048 MW due to lack of gas supply or transportation interruptions. Cold weather related equipment failure was the third category accounting for 7,701 MW. Figure 3-55 and Figure 3-56 show the hourly generator outages on December 23 and 24, 2022.

Figure 3-55 December 23, 2022 outages

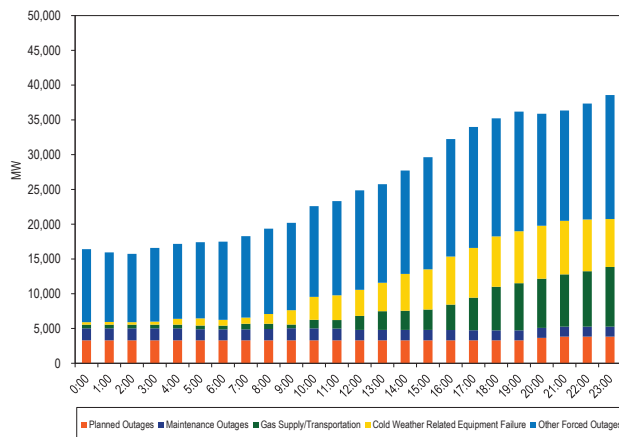
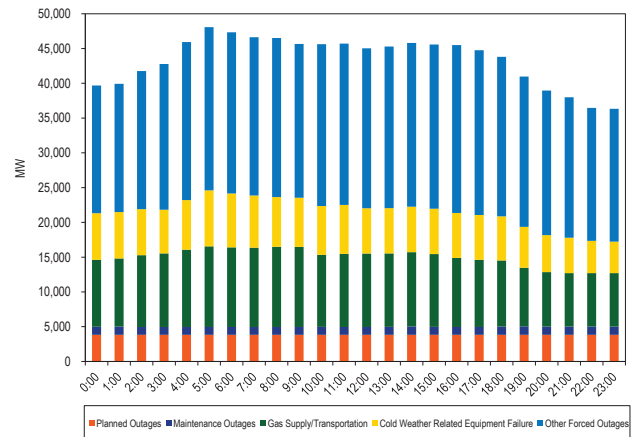


Figure 3-56 December 24, 2022 outages



Performance

On December 23 and December 24, 2022, most unit types (as a group) failed to perform to nameplate capacity. Table 3-86 compares nameplate capacity to actual performance (actual performance measured as energy produced plus regulation and reserve assignments). Table 3-86 shows that on average, generators provided energy and ancillary services at 71 percent (or 29 percent under performance) of the total nameplate capacity or 56,322 MW short of total nameplate capacity. Only nuclear, as a group, over performed. Table 3-86 also shows that 7,058 MW was provided by resources that did not have a capacity commitment.

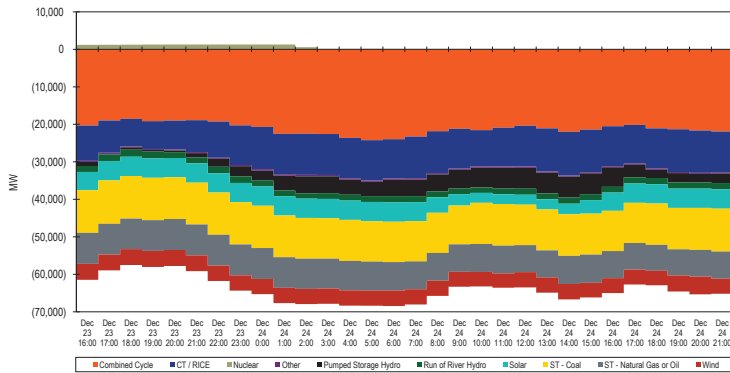
Combined cycles failed to perform mainly due to equipment related forced outages and lack of fuel. Coal units failed to perform mainly due to equipment related forced outages. Gas fired and oil fired steam turbines failed to perform mainly because those units are normally offline and have long start times.

Table 3-86 Unit Performance on December 23 at 1800 EPT by group

Unit/Fuel Type	Committed ICAP (MW)	ICAP (MW)	Actual Performance (MW)	Over/Under Performance (MW)	Over/Under Performance (%)
Combined Cycles	54,218	55,448	36,908	(18,539)	67%
Dual Fuel	11,493	11,862	5,754	(6,107)	49%
Natural Gas	42,725	43,586	31,154	(12,432)	71%
Combustion Turbines / RICE	26,735	28,835	21,491	(7,344)	75%
Dual Fuel	10,417	11,222	10,148	(1,074)	90%
Natural Gas	13,226	14,134	8,417	(5,716)	60%
Oil	3,092	3,479	2,925	(554)	84%
Nuclear	27,831	32,749	33,996	1,247	104%
Other	1,313	1,434	1,186	(249)	83%
Pumped Storage Hydro	5,125	5,575	4,940	(635)	89%
Run of River Hydro	2,214	3,620	1,750	(1,869)	48%
ST - Coal	40,956	43,407	32,048	(11,359)	74%
ST - Natural Gas or Oil	9,263	9,707	1,561	(8,146)	16%
Solar	3,916	5,153	0	(5,153)	0%
Wind	6,608	10,869	6,633	(4,236)	61%
Total	178,180	196,796	140,514	(56,282)	

Figure 3-57 shows the hourly breakdown of the unit performance by group starting on December 23, 1600 EPT through December 24, 2200 EPT. During all hours, only nuclear above committed nameplate capacity.¹¹⁵

Figure 3-57 December 23, 1600 EPT through December 24, 2200 EPT unit performance



Performance Assessment Intervals

On December 23, at 1730 EPT, PJM declared a Maximum Generation Action until 2300 EPT (55 intervals). On December 24, at 0425 EPT, PJM declared a Maximum Generation Action until 2200 EPT (211 intervals). Both actions resulted in RTO wide performance assessment intervals. Between December 23 and 24, 2022, there were 277 performance assessment intervals. This was the first time since Capacity Performance was implemented that PJM triggered an RTO wide PAI.

The performance of CP resources required to pay a penalty or receive a bonus is defined differently for different types of resources. For generation and storage resources, the performance is defined as the committed unforced capacity (UCAP) times the Balancing Ratio (B). For demand response resources, the performance is defined as the committed capacity, and is not affected by the balancing ratio.

¹¹⁵ 1,139 MW of nuclear MW did not perform starting on 0220 EPT on December 24.

The Balancing Ratio is defined, for each PAI, as:

$$\text{Balancing Ratio} = \frac{\text{All Actual Generation and Storage Performance} + \text{Net Energy Imports} + \text{PRD Bonus Performance} + \text{DR Bonus Performance}}{\text{All Generation and Storage Committed UCAP}}$$

Actual Generation Performance includes metered output of energy as well as real-time reserves and regulation assignments during each PAI. Actual Demand Resource Performance includes the demand reductions provided as well as real-time reserves and regulation assignments during each PAI. Actual Energy Efficiency Performance includes the load reduction quantity approved by PJM prior to the beginning of the delivery year based on the submitted measurement and verification report which is based on assumed performance.

Demand resource actual performance is defined in the PJM tariff as the sum of demand response provided by a resource for each five minute interval, and the real-time reserve and regulation assigned.¹¹⁶ Demand response bonus performance is calculated for each resource as:¹¹⁷

$$\text{DR Bonus Performance} = \text{Actual Performance} - \text{Expected Performance}$$

The guiding principle of PJM's Capacity Performance design is that resources that do not perform do not get paid regardless of the reason for nonperformance. The guiding principle is that there are no excuses for nonperformance.

Resources with committed capacity must meet their required level of performance or pay nonperformance assessment charges, resources that exceed their required level of performance are paid bonuses, but resources are excused from performing if they are on a planned or maintenance outage or based on specific PJM dispatch instructions.

PJM estimated that resources incurred \$1 to \$2 billion of penalties on December 23 and 24, 2022.¹¹⁸ These values were preliminary since PJM still needed to include PRD and DR performance and review excuses for nonperformance. Final penalties are expected in the second quarter of 2023.

Resources that do not perform because they are on an approved planned or maintenance outage are excused. Resources that do not perform because PJM did not schedule them to operate or PJM dispatched them down are excused. But the reason for that inaction (not scheduled) or action (dispatched down) cannot be an operating parameter limitation submitted by the resource or the inclusion of a positive markup in the price-based offers.

Prices

Real-Time Prices

On December 23 and December 24, 2022, real-time load-weighted average hourly LMP was extremely high, with the peak LMP exceeding \$3,500 per MWh. The corresponding real-time load-weighted average hourly LMP in the dispatch run was even higher, with the peak LMP exceeding \$4,500 per MWh. Figure 3-58 shows the components of the PJM real-time load-weighted average hourly LMP in the dispatch run for each hour on December 23. Figure 3-58 shows the components of the PJM real-time load-weighted average hourly LMP in the pricing run for each hour on December 23. Figure 3-59 shows the components of the PJM real-time load-weighted average hourly LMP in the dispatch run for each hour on December 24. Figure 3-61 shows the components of the PJM real-time load-weighted average hourly LMP in the pricing run for each hour on December 24. On December 23, for the hour beginning at 1700 (EPT), 76 percent of the load-weighted average LMP in the dispatch run was due to reserve penalty factors, 15 percent was due to transmission penalty factors and the remaining 10 percent was due to the cost of fuel and markups of marginal generation resources. On December 23 and December 24, PJM was short of meeting reserve

¹¹⁶ OATT Attachment DD Section 10.A (c).

¹¹⁷ OATT Attachment DD Section 10.A (g).

¹¹⁸ See "Winter Storm Elliott," slide 26, PJM presentation to the Resource Adequacy Senior Task Force. (January 11, 2023) <<https://pjm.com/-/media/committees-groups/committees/mic/2023/20230111/item-0x--winter-storm-elliott-overview.ashx>>.

requirements in all reserve pricing zones for several hours. During the reserve shortage, the reserve prices were set by the reserve penalty factors. Under PJM’s joint optimization of energy and reserves, the marginal cost of providing energy includes the penalty cost of reserves if the marginal resource setting LMP forgoes providing reserves to generate energy.

On December 23 and December 24, PJM capped the energy LMP in the pricing run at \$3,700 per MWh. On December 23, for the hour beginning at 1700, the load-weighted average LMP was reduced by \$2,205.82 per MWh or 37 percent from \$5,912.68 per MWh to \$3,706.86 per MWh. For this hour, in the pricing run, 76 percent of the uncapped load-weighted average LMP was due to reserve penalty factors and 12 percent was due to transmission penalty factors.

PJM called emergency demand response between 1730 (EPT) hours and 2215 (EPT) hours on December 23 and again between 0420 (EPT) hours and 2030 (EPT) hours on December 24. The offers of the emergency demand response set pricing run and dispatch run LMPs for several five minute intervals during this time period. For example, as shown in Figure 3-59 for the hour beginning at 1900 (EPT), 31 percent of the uncapped load-weighted average LMP in the pricing run was due to demand response resources. Unlike generation resources, the actual performance of demand response resources in real time is not known to PJM. PJM dispatch and pricing run models rely on a projected performance of these resources for balancing generation and load and for calculating marginal prices.

Figure 3-58 Components of real-time (Unadjusted) dispatch run load-weighted average LMP: December 23

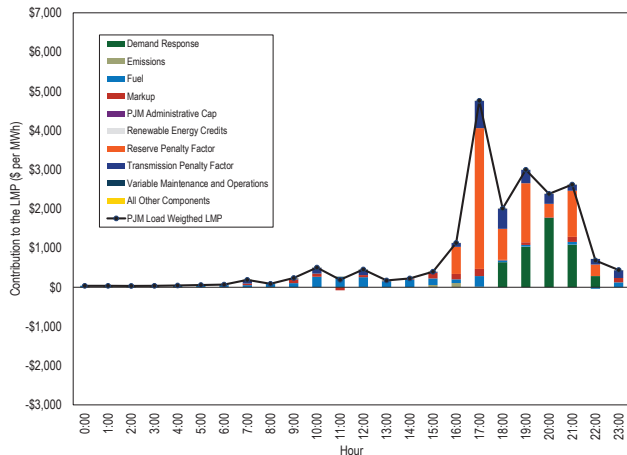


Figure 3-59 Components of real-time (Unadjusted) pricing run load-weighted average LMP: December 23

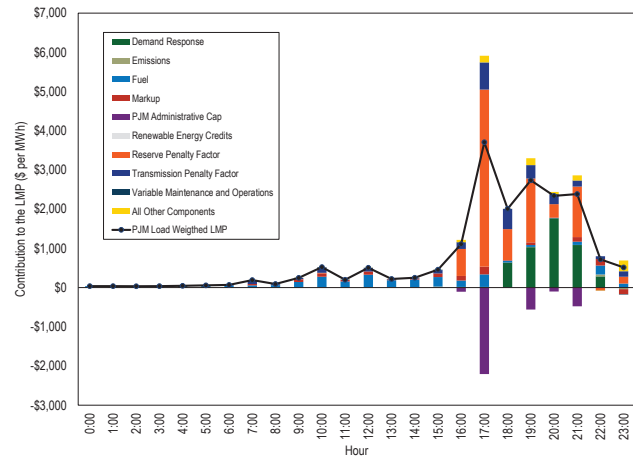


Figure 3-60 Components of real-time (Unadjusted) dispatch run load-weighted average LMP: December 24

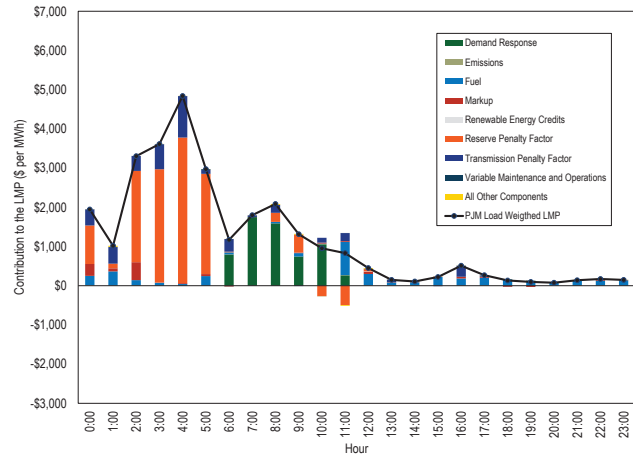
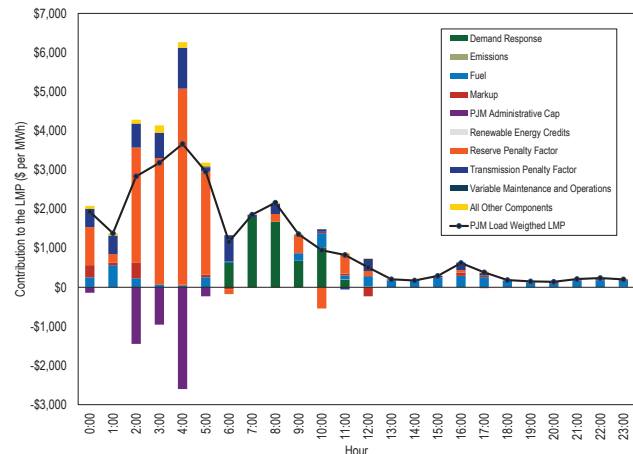


Figure 3-61 Components of real-time (Unadjusted) pricing run load-weighted average LMP: December 24



Day-Ahead Prices

During Elliott on December 23 and December 24 of 2022, day-ahead load-weighted average hourly LMP in PJM in the pricing run were high with LMP exceeding \$250 per MWh. The corresponding day-ahead load-weighted average hourly LMP in the dispatch run with the LMP exceeding \$250 per MWh. Figure 3-62 shows the components of the PJM day-ahead load-weighted average hourly LMP in the dispatch run for each hour on December 23, 2022. Figure 3-63 shows the components of the PJM day-ahead load-weighted average hourly LMP in the pricing run for each hour on December 23, 2022. Figure 3-64 shows the components of the PJM day-ahead load-weighted average hourly LMP in the dispatch run for each hour on December 24, 2022. Figure 3-65 shows the components of the PJM day-ahead load-weighted average hourly LMP in the pricing run for each hour on December 24, 2022.

On December 23 of 2022, markup component of LMP was high for the hour beginning at 0000 EPT and the hour beginning at 1600 EPT which were \$89.3 per MWh and \$55.6 per MWh respectively. The fuel component of LMP was high for the hour beginning at 1100 EPT and the hour beginning at 2100 EPT which were \$131.2 per MWh and \$158.6 per MWh respectively in the dispatch run.

On December 23 of 2022, in the pricing run, markup component of LMP was lowest for the hour beginning at 1100 EPT which was -\$216.1 per MWh and the fuel component of LMP was highest which was \$368.5 per MWh for the same hour. On December 23 of 2022, in the pricing run, Up to Congestion Transactions (UTCs) contributed 100 percent of the load-weighted average LMP for 14 hours.

On December 24 of 2022, in the dispatch run, the fuel component of LMP was high for the hour beginning at 0000 EPT and the hour beginning at 1900 EPT which were \$277.8 per MWh and \$333.3 per MWh. On December 24 of 2022, in the pricing run, the fuel component of LMP was high for the hour beginning at 0300 EPT and the hour beginning at 0400 EPT which were \$1,441.1 per MWh and \$1,203.7 per MWh.

Figure 3-62 Components of day-ahead (Unadjusted) dispatch run load-weighted average LMP: December 23, 2022

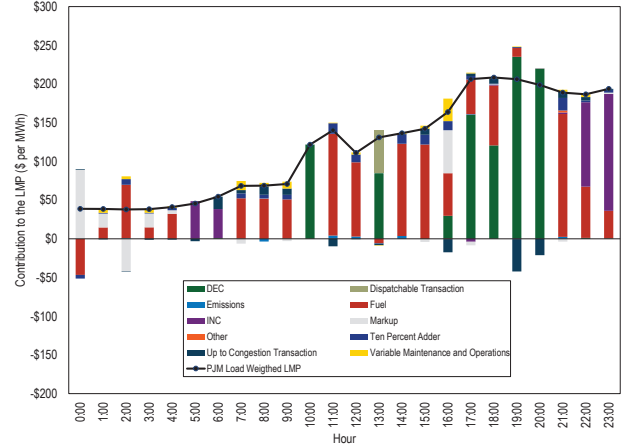


Figure 3-63 Components of day-ahead (Unadjusted) pricing run load-weighted average LMP: December 23, 2022

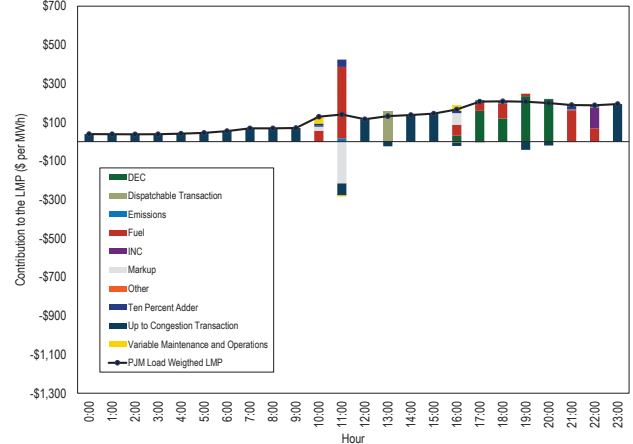


Figure 3-64 Components of day-ahead (Unadjusted) dispatch run load-weighted average LMP: December 24, 2022

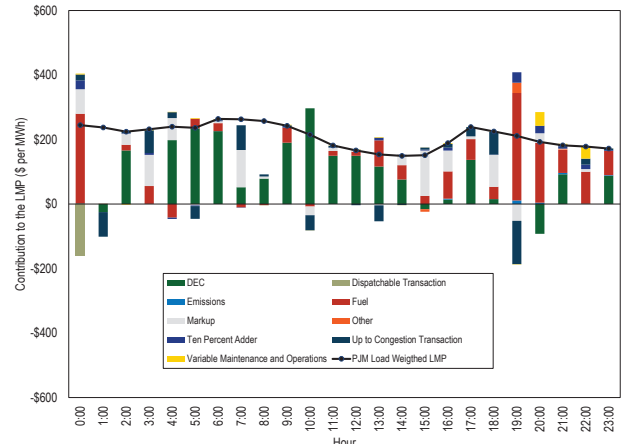
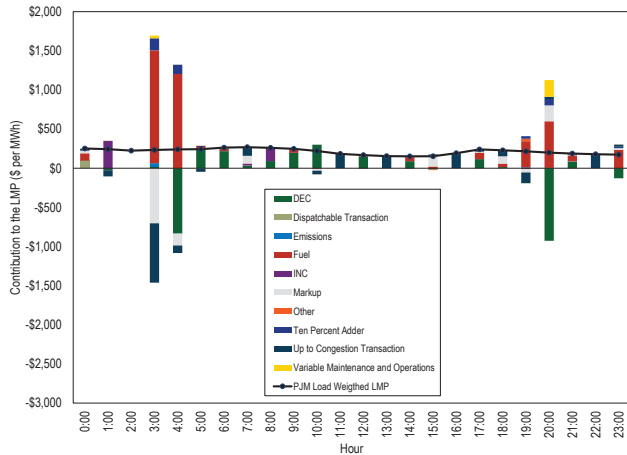


Figure 3-65 Components of day-ahead (Unadjusted) pricing run load-weighted average LMP: December 24, 2022



Power Balance Constraint Violation

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

The current process for meeting energy and reserve requirements in real time, and pricing the system conditions when RT SCED forecasts that energy supply is less than the demand for energy and reserves, is opaque and not defined in the PJM governing documents. It is unclear whether and how PJM converts reserves to energy before violating the power balance constraint. It is unclear whether and when PJM uses its authority under the tariff to curtail exports from PJM capacity resources to meet the power balance constraint. It is unclear whether PJM would maintain a minimum level of synchronized reserves even if that would result in a controlled load shed. The current RT SCED does not have a mechanism to convert inflexible reserves procured by the ASO to energy to satisfy the power balance constraint.¹¹⁹ SCED solutions from October 1, 2019, February 16, 2020, and April 21, 2020, indicate that the currently defined logic meets transmission constraint

limits and reserve requirements but violates the power balance constraint, and does not reflect this constraint violation in prices. This logic, if correctly described and if there was an actual power balance constraint violation, is not consistent with basic economics. The overall solution is complex and must be integrated with the approach to shortage pricing. During Elliot, on December 23, 2022, and December 24, 2022, PJM created what they termed “virtual” generation in real time to satisfy the power balance constraint. PJM did not convert any inflexible reserves to energy. In summary, the power balance constraint was violated solely as a result of load bias added by PJM and that violation was corrected by PJM adding generation that does not exist to the supply (virtual generation or supply bias). To the extent that there was an actual violation of the power balance constraint, it was appropriate that PJM did not take actions to address the nonexistent violation. But the process needs to be clarified to help ensure that an artificial power balance constraint violation does not affect prices.

The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. Table 3-87 shows the number of five minute intervals for which the RT SCED solutions did not balance demand and supply. PJM reran the RT SCED with artificially increased supply to satisfy the power balance constraint. In 2022, there were 121 five minute intervals using an RT SCED solution with a violated power balance constraint. The prices differed between the dispatch run and the pricing run in December 2022 due to PJM’s application of system marginal price capping in the pricing run only.

¹¹⁹ Inflexible reserves are those reserves that clear in the hour ahead Ancillary Service Optimizer (ASO) but cannot be dispatched in the real time dispatch tool, RT SCED.

Table 3-87 Number of five minute intervals using RT SCED solutions with violated power balance constraint by year

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

Figure 3-66 Power balance constraint violations: December 23 and Figure 3-67 Power balance constraint violations: December 24 show forecasted load including operator load bias and total cleared generation, demand response and net scheduled interchange in the SCED solutions approved for each five minute interval on December 23, 2022 and December 24, 2022 during Elliott. There is a power balance violation when the forecasted load plus losses plus operator bias (blue curve) exceeds the generation plus demand response plus net interchange (orange curve).

Figure 3-66 Power balance constraint violations: December 23

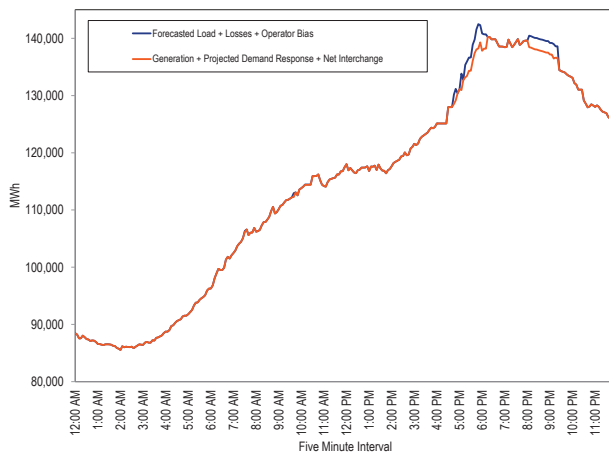
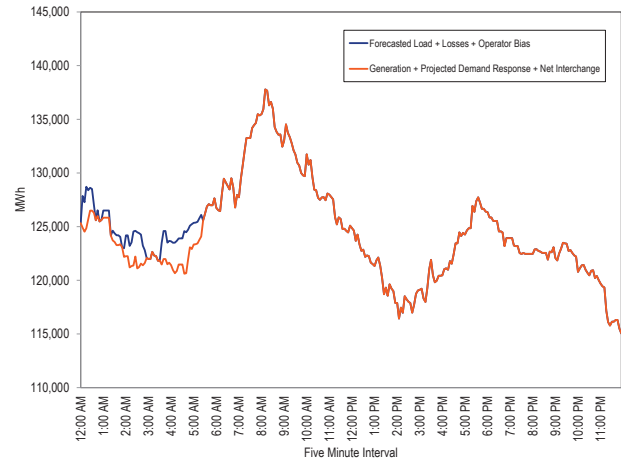


Figure 3-67 Power balance constraint violations: December 24



Shortage and Shortage Pricing

In electricity markets, shortage means that demand, including reserve requirements, is nearing the limits of the currently available capacity of the system. Shortage pricing is a mechanism for signaling scarcity conditions through higher energy prices. Under the PJM rules that were in place through September 30, 2012, shortage pricing resulted from the exercise of aggregate market power by individual generation owners for specific units when the system was close to its available capacity. But this was not an efficient way to manage shortage pricing and made it difficult to distinguish between market power and shortage pricing. Shortage pricing is an administrative pricing mechanism in which PJM sets a high energy price at a predetermined level when the system operates with less real-time reserves than required.

In 2022, there were 270 five minute intervals with shortage pricing that occurred on 22 days in PJM.

In Order No. 825, the Commission required each RTO/ISO to trigger shortage pricing for any dispatch and pricing interval in which a shortage of energy or operating reserves is indicated by the RTO/ISO's software.¹²⁰ 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

¹²⁰ 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).

declared, and shortage pricing was not implemented. As of May 11, 2017, the rule requires PJM to trigger shortage pricing for any five minute interval for which the Real-Time SCED (Security Constrained Economic Dispatch) indicates a shortage of synchronized reserves or primary reserves. In January 2019, PJM updated its business rules in Manual 11 to describe PJM's implementation of the five minute shortage pricing process. PJM Manual 11 states that shortage pricing is triggered when an approved RT SCED case that was used in the Locational Pricing Calculator (LPC) indicates a shortage of reserves. The implementation is not as algorithmic as intended by Order No. 825, because RT SCED can indicate a shortage that PJM does not use in pricing. On June 22, 2020, PJM reduced the frequency of automatic RT SCED executions to match the frequency of pricing at five minutes, which reduced the frequency of unpriced shortage solutions.

Prior to September 1, 2021, the reserves calculated in the LPC solution, and the reserves calculated in the reference RT SCED case used by the LPC solution were the same. With the implementation of fast start pricing on September 1, 2021, shortage pricing is now triggered by the pricing run in LPC.¹²¹ This can lead to differences between the dispatched reserves in RT SCED, and the reserves calculated in the pricing run in LPC. In the pricing run in LPC, shortage pricing could be triggered even when there is no actual shortage in dispatched reserves as determined by the reference RT SCED solution. This occurred during ten intervals in 2022.¹²²

Voltage reduction actions and manual load dump actions are also triggers for shortage pricing, reflecting the fact that when operators need to take these emergency actions to maintain reliability, the system is short reserves and prices should reflect that condition, even if the data do not show a shortage of reserves.¹²³

Operating Reserve Demand Curves

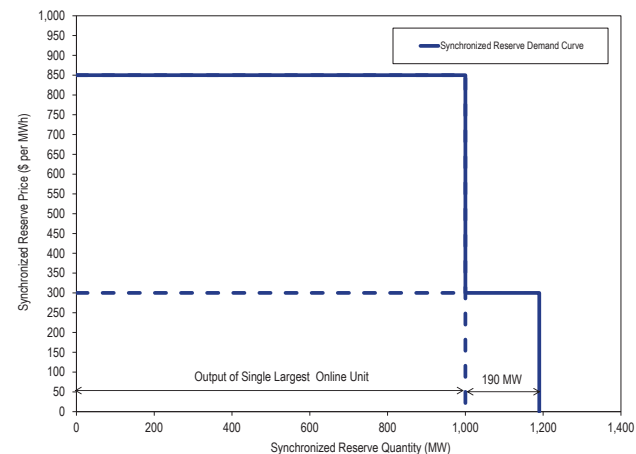
Shortage pricing in the PJM Energy Market can occur in either the day-ahead or the real-time market for any of five reserves requirements: RTO Synchronized Reserves, Subzone Synchronized Reserves, RTO Primary Reserves, Subzone Primary Reserves, and 30 Minute Reserves. Each requirement is modelled in 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 an additional 190 MW of reserves. When a reserve constraint is not satisfied, the value on the demand curve for the cleared amount of reserves is added to the market clearing cost-minimization objective function, which makes the demand curve value the administratively determined marginal cost of the reserve shortage.

Shortage Pricing and Energy Price Formation

The current operating reserve demand curves (ORDC) in PJM define an administrative price for estimated reserves (primary and synchronized reserves) up to the extended reserve requirement quantities. The demand curve shown in Figure 3-68 Real-time synchronized reserve demand curve showing the permanent second step drops to a zero price for quantities above the extended reserve requirement. The price for reserve quantities less than the reserve requirement is \$850 per MWh, and the price for reserve quantities above the reserve requirement to 190 MW above the reserve requirement is \$300 per MWh.

Figure 3-68 Real-time synchronized reserve demand curve showing the permanent second step



Nesting

The reserve requirements are nested such that the faster responding reserves count toward the requirements for slower reserves and such that the reserves in the subzone count toward the total RTO requirement. For example, synchronized reserves count toward the primary reserve

¹²¹ See PJM Operating Agreement, Schedule 1, Section 2.5.1(a).

¹²² The seven intervals include a case in which both RTO and MAD were short in the pricing run but only MAD was short in the dispatch run.

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).

requirement, and Mid-Atlantic Dominion reserves count toward the PJM RTO reserve requirement. This nesting means that the effect of reserve constraints on prices can be additive.

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

Energy and Reserve Price Caps

Table 3-88 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.

In scenario B, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones that results in a \$1,700 per MWh reserve shortage penalty in the RTO zone LMP and a \$3,400 per MWh reserve shortage penalty in the MAD Zone LMP. The marginal resource for energy is in the RTO Zone, and the RTO to MAD reserve transfer constraint is not binding, so the higher MAD reserve penalty does not affect the rest of RTO LMP. In scenario C, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones and a violated transmission constraint that affects the marginal congestion costs in the system marginal price.

In scenario C, the sum of the marginal unit cost, reserve and transmission constraint penalty factors equals \$5,450 per MWh, which exceeds \$3,700 per MWh, so SMP capping is triggered whether the marginal unit for

energy can provide reserves for the MAD Zone or only the RTO Zone.

In scenario D, with a \$1,000 per MWh offer price for the marginal unit for energy, violation of four reserve penalty factors only triggers SMP capping if the marginal unit for energy can serve the MAD reserve requirement. Scenario E and F show that LMPs can exceed \$3,700 per MWh if there is a violated transmission constraint that is not exacerbated by an increase in load at the load weighted reference pricing node, which determines the SMP.¹²⁴

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

¹²⁴ The impact of the transmission constraint penalty factor at a pnode depends on its distribution factor (dfax) with respect to the constraint. The scenarios here assume a single violated transmission constraint with dfax of 1.0. If there are multiple violated transmission constraints, the total impact at a pnode is the sum of the product of transmission constraint penalty factors and distribution factors.

Table 3-88 Real-time additive penalty factors under reserve shortage and transmission constraint violations: Status Quo

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

Circuit Breaker

Due to the high prices that were possible under PJM's proposed ORDCs and the February 2021 experiences of market participants in the ERCOT market, PJM stakeholders initiated a discussion about a circuit breaker mechanism that would reduce prices in circumstances that would otherwise result in prolonged high LMPs. In the absence of an efficient shortage pricing mechanism, reducing the application of transmission constraint penalty factors and reducing reserve penalty prices during extended emergency situations would minimize the market harm done by administrative pricing without implementing an inefficient price capping process. While FERC's remand order maintains the current levels of emergency pricing, rather than PJM's higher proposed levels, there remain possible scenarios in which prolonged and excessively high administrative pricing in the energy market under the current tariff provisions would impose inefficient wealth transfers. Inefficient wealth transfers from load to generation, among generators, or from physical to financial market participants occur when administrative pricing creates arbitrarily high price signals to which participants cannot respond. A better solution than a circuit breaker would be to lower the default emergency pricing levels to avoid inefficient wealth transfers.

Some of the circuit breaker proposals made in the stakeholder process would have applied during Elliott. The PJM load-weighted average LMP was greater than \$1,000 per MWh for a 24 hour period. Of the hours when LMP was greater than \$1,000 per MWh, only one hour on December 24 reached that level as a result of high fuel prices (Figure 3-60). In all other hours, administrative components of LMP set prices above \$1,000 per MWh. MMU proposes that only the administrative components of LMP be capped. Administrative components include ORDC penalty factors, transmission constraint penalty

factors, and the maximum demand response strike price. Capping administrative components would prevent arbitrarily high prices while ensuring that the actual costs of meeting demand are included in prices.

Operator Actions

Actions taken by PJM operators to maintain reliability, such as committing more reserves than required, may suppress reserve prices. The need to commit more reserves could instead be directly reflected in the ORDC when operational issues arise, allowing the market to efficiently account for the reliability commitment in the energy and reserves markets. During Elliott, PJM committed additional generation to provide reserves but did not increase the reserve requirements accordingly.

Locational Reserve Requirements

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

Shortage Pricing During Synchronized Reserve Events

Synchronized reserves are deployed when PJM declares a synchronized reserve event, also known as a spinning event. Currently, spinning events are triggered by an all call message to the system requesting all online generation units to increase their energy output. This deployment mechanism is used regardless of the actual MW needed to recover the Area Control Error (ACE) to zero or to the pre-event levels. Generally, the cause of the spinning event is a unit trip. Occasionally, PJM also declares spinning events to recover ACE when generators

do not follow dispatch instructions to increase output. The response solicited through the all call message during a spinning event is much greater than the MW lost and MW needed to recover the ACE. This results in an overshoot of the ACE to positive values beyond the target range. There is currently no mechanism for PJM to selectively load synchronized reserves in proportion to the MW needed to recover ACE to zero or the pre-event levels, even though the PJM market rules allow PJM to load a proportion of reserves. While the all-call message signals resources to increase their output, the approved SCED cases are solved with the reserve requirement intact, which dispatches the system to meet the load and reserve requirements ten to fourteen minutes into the future. This results in a discrepancy between the operational need during a spinning event, and the RT SCED solutions. PJM's instruction to generators is to ignore the dispatch signals sent by RT SCED, and instead continue to ramp their units up until the spin event ends. Since the LMPs do not reflect the need for the generators to ramp up their resources, until October 1, 2022, PJM paid a \$50 per MWh premium to all resources, except Tier 2 cleared resources, that increased their output in response to a spinning event.

Under the reserve market enhancements that began October 1, 2022, all synchronized reserves are treated as a uniform product and paid the market clearing price for synchronized reserves. All synchronized reserves are also assessed a penalty for nonperformance during the synchronized reserve events. Deployment of reserves during synchronized reserve events will be most efficient if the resources that are deployed and are subject to performance evaluation for their response are the resources that are committed as synchronized reserves. However, under PJM's proposed Intelligent Reserve Deployment (IRD) approach, PJM would rely on units that do not have a reserve commitment, while unnecessarily holding back committed and compensated reserve units during a spin event.¹²⁵ This is because the IRD approach is just a SCED solution based on: load increased by a predetermined amount; inflexible synchronized reserves converted to energy production; and maintaining the reserve requirement. The result is that inflexible synchronized reserves are converted to energy production, while flexible resources are held

as reserves to meet the reserve requirement instead of responding to the spin event. Since PJM proposes penalties for lack of response during spin events for cleared and dispatched reserves, this results in inflexible synchronized reserve resources potentially being subject to penalties disproportionately, while flexible synchronized reserves may or may not be dispatched, and consequently may not be subject to penalties. The IRD mechanism also creates a reliability risk since it relies on resources not committed as reserves to increase their output to recover ACE during a spin event, and these resources are not subject to a penalty for nonperformance. For these reasons, FERC rejected PJM's IRD proposal on August 15, 2022.¹²⁶

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

Reserve Shortages in 2022

Reserve Shortage in Real-Time SCED

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

¹²⁵ PJM, "Intelligent Reserve Deployment PJM Package," presented at the Synchronous Reserve Deployment Task Force, (July 1, 2021) at 3, which can be accessed at <<https://www.pjm.com/-/media/committees-groups/task-forces/srdtf/2021/20210701/20210701-item-03-pjms-proposed-package-intelligent-reserve-deployment.ashx>>.

¹²⁶ See PJM Interconnection, L.L.C., 180 FERC ¶ 61,089 (August 15, 2022).

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.^{127 128} 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 3-89 shows, for each month of 2021 and 2022, 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. Prior to June 3, 2021, each execution of RT SCED produced three solutions, using three different levels of load bias. Beginning June 3, 2021, each execution of RT SCED produces five solutions, using five different levels of load bias. This resulted in an increase in RT SCED cases with reserve shortages in at least one of the solutions. Table 3-89 shows that, in 2022, 9,026 target times, or 8.6 percent of all five minute target times, had at least one RT SCED solution showing a shortage of reserves, and 2,766 target times, or 2.6 percent of all five minute target times, had more than one RT SCED solution showing a shortage of reserves. In 2021, there were 5,590 target times, or 5.3 percent of all five minute target times, that had at least one RT SCED solution showing a shortage of reserves, and 1,572 target times, or 1.5 percent of all five minute target times, that had more than one RT SCED solution showing a shortage of reserves.

Table 3-89 Real-time monthly five minute SCED target times and pricing intervals with shortage: January 2021 through December 2022

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
2021 Jan	8,928	114	1.3%	22	0.2%	0	0.0%
2021 Feb	8,064	108	1.3%	28	0.3%	0	0.0%
2021 Mar	8,916	198	2.2%	46	0.5%	4	2.0%
2021 Apr	8,640	130	1.5%	24	0.3%	0	0.0%
2021 May	8,928	235	2.6%	48	0.5%	5	2.1%
2021 Jun	8,640	516	6.0%	165	1.9%	1	0.2%
2021 Jul	8,928	460	5.2%	104	1.2%	0	0.0%
2021 Aug	8,928	429	4.8%	131	1.5%	7	1.6%
2021 Sep	8,640	545	6.3%	169	2.0%	2	0.4%
2021 Oct	8,928	730	8.2%	232	2.6%	2	0.3%
2021 Nov	8,652	1,320	15.3%	405	4.7%	4	0.3%
2021 Dec	8,928	805	9.0%	198	2.2%	3	0.4%
2021 Total	105,120	5,590	5.3%	1,572	1.5%	28	0.5%
2022 Jan	8,928	904	10.1%	276	3.1%	14	1.5%
2022 Feb	8,064	544	6.7%	153	1.9%	0	0.0%
2022 Mar	8,916	1,306	14.6%	381	4.3%	5	0.4%
2022 Apr	8,640	1,114	12.9%	343	4.0%	3	0.3%
2022 May	8,928	1,008	11.3%	265	3.0%	1	0.1%
2022 Jun	8,640	714	8.3%	170	2.0%	38	5.3%
2022 Jul	8,928	785	8.8%	223	2.5%	1	0.1%
2022 Aug	8,928	927	10.4%	263	2.9%	0	0.0%
2022 Sep	8,640	731	8.5%	187	2.2%	0	0.0%
2022 Oct	8,928	399	4.5%	151	1.7%	1	0.3%
2022 Nov	8,652	138	1.6%	46	0.5%	0	0.0%
2022 Dec	8,928	456	5.1%	308	3.4%	207	45.4%
2022 Total	105,120	9,026	8.6%	2,766	2.6%	270	3.0%

¹²⁷ 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.

¹²⁸ 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.

In 2022, there were 270 five minute intervals with shortage pricing, while there were 2,766 five minute target times for which multiple RT SCED solutions showed a shortage of reserves. In 2021, there were 28 five minute intervals with shortage pricing, while 1,572 five minute target times for which multiple RT SCED solutions showed a shortage of reserves. Clear criteria for approval of shortage cases are needed.

The PJM Real-Time Energy Market produces an efficient outcome only when prices are allowed to reflect the fundamental supply and demand conditions in the market in real time. While it is appropriate for operators to ensure that cases use data that reflect the actual state of the system, it is essential that operator discretion not extend beyond what is necessary and that operator discretion not prevent shortage pricing when there are shortage conditions or implement shortage pricing when there are no shortage conditions. This is a critical issue now that PJM settles all real-time energy transactions on a five minute basis using the prices calculated by LPC. The pattern of shortage case approvals in Table 3-89 indicates that PJM operators consider factors other than RT SCED and LPC results when deciding whether to approve shortage cases. After a 5.3 percent approval rate in June 2022, the approval rate dropped to close to zero percent until December 2022 when it rose to 45.4 percent. The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases that are used to send dispatch signals to resources, and for pricing, to minimize discretion. A rule based approach is essential for defining how LMPs are determined so that all market participants can be confident that energy market pricing is efficient.

Shortage Pricing Intervals in LPC

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

There were 270 five minute intervals with shortage pricing in 2022, compared to 28 intervals in 2021. PJM implemented fast start pricing on September 1, 2021. This resulted in differences in reserve shortages between the dispatch run and the pricing run in 2022. In 2022, there were 270 five minute intervals with shortage pricing in

the pricing run, and 260 intervals with shortage in the dispatch run.

Table 3-90 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 98 intervals with shortage pricing in the pricing run due to synchronized reserve shortage in 2022. Table 3-90 shows that 92 out of the 98 intervals had synchronized reserve shortage for the RTO Reserve Zone in the dispatch run. Table 3-91 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the MAD Reserve Subzone during the 89 intervals with shortage pricing in the pricing run due to synchronized reserve shortage in 2022. Table 3-91 shows that all 88 intervals had synchronized reserve shortage for the MAD Subzone in both the dispatch run and pricing run with identical capped market clearing prices.

Table 3-92 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 242 intervals with shortage pricing in the pricing run due to primary reserve shortage in 2022. Table 3-92 shows that in 235 out of the 242 intervals there was no shortage of primary reserves in the dispatch run. Table 3-93 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 225 intervals with shortage pricing in the pricing run due to primary reserve shortage in 2022.

Table 3-94 shows the extended 30 minute reserve requirement, the total 30 minute reserves, the 30-minute reserve shortage, and the primary reserve clearing prices for the RTO Zone during the 16 intervals with shortage pricing in the pricing run due to 30 minute reserve shortage in 2022. There is currently no 30 minute reserve requirement defined for the MAD Subzone. Table 3-94 shows that all of the intervals that were short of 30 minute reserves in the pricing run were also short in the dispatch run.

PJM enforces an RTO wide reserve requirement and a supplemental 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.¹²⁹ 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.

Table 3-90 Summary of real-time RTO synchronized reserve shortage intervals: 2022¹³⁰

Day (EPT)	Pricing Run						Dispatch Run				
	Average RTO Extended Synchronized Reserve Requirement	Average Total RTO Synchronized Reserves	Average RTO Synchronized Reserve Shortage	Average Uncapped RTO Synchronized Reserve Clearing Price	Average Capped RTO Synchronized Reserve Clearing Price	Average RTO Extended Synchronized Reserve Requirement	Average Total RTO Synchronized Reserves	Average RTO Uncapped RTO Synchronized Reserve Shortage	Average Uncapped RTO Synchronized Reserve Clearing Price	Average Capped RTO Synchronized Reserve Clearing Price	
	(MW)	(MW)	(MW)	(\$/MWh)	(\$/MWh)	(MW)	(MW)	(MW)	(\$/MWh)	(\$/MWh)	
	Intervals of Shortage	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 Uncapped RTO Synchronized Reserve Shortage (MW)	Uncapped RTO Synchronized Reserve Clearing Price (\$/MWh)	Capped RTO Synchronized Reserve Clearing Price (\$/MWh)
13-Jan-22	2	1,700.0	1,700.0	2,328.430	\$2,328.43	\$1,804.00	1,804.0	450.247	\$1,353.75	\$1,353.75	
16-Jan-22	1	401.3	401.3	401.310	\$401.31	\$1,859.00	1,859.0	190.000	\$1,669.00	\$1,669.00	
30-Jan-22	2	300.0	300.0	300.000	\$300.00	\$1,800.50	1,800.5	95.914	\$1,704.60	\$1,704.60	
31-Jan-22	4	638.2	668.3	638.225	\$675.44	\$1,714.00	1,714.0	141.822	\$1,572.18	\$1,572.18	
2-Mar-22	2	407.8	407.8	407.755	\$407.76	\$1,639.50	1,639.5	153.000	\$1,486.50	\$1,486.50	
12-Mar-22	1	300.0	300.0	300.000	\$300.00	\$1,825.00	1,825.0	116.900	\$1,708.10	\$1,708.10	
20-Mar-22	1	300.0	300.0	300.000	\$300.00	\$1,642.00	1,642.0	5.800	\$1,636.20	\$1,636.20	
21-Mar-22	1	300.0	300.0	300.000	\$300.00	\$1,722.00	1,722.0	0.000	\$1,722.00	\$1,722.00	
13-Apr-22	1	300.0	300.0	300.000	\$300.00	\$1,534.70	1,534.7	84.200	\$1,450.50	\$1,450.50	
14-Apr-22	1	300.0	300.0	300.000	\$300.00	\$1,533.70	1,533.7	73.800	\$1,459.90	\$1,459.90	
19-Apr-22	1	269.7	300.0	269.720	\$300.00	\$1,536.10	1,536.1	0.000	\$1,536.10	\$1,536.10	
16-May-22	1	300.0	300.0	300.000	\$300.00	\$1,789.00	1,789.0	108.900	\$1,680.10	\$1,680.10	
13-Jun-22	11	1,100.0	1,100.0	1,100.000	\$1,100.00	\$1,767.55	1,767.5	51.400	\$1,716.18	\$1,716.18	
27-Jun-22	2	575.0	575.0	575.000	\$575.00	\$1,796.50	1,796.5	95.000	\$1,701.50	\$1,701.50	
29-Jun-22	1	399.2	399.2	399.180	\$399.18	\$2,712.80	2,712.8	187.400	\$2,525.40	\$2,525.40	
28-Jul-22	1	814.4	814.4	814.410	\$814.41	\$1,757.00	1,757.0	190.000	\$1,567.00	\$1,567.00	
12-Oct-22	1	300.0	300.0	300.000	\$300.00	\$2,728.00	2,728.0	17.200	\$2,710.80	\$2,710.80	
23-Dec-22	23	1,656.4	1,652.2	1,656.369	\$1,656.37	\$1,861.00	1,861.0	572.347	\$1,288.65	\$1,288.65	
24-Dec-22	38	1,518.4	1,526.3	1,518.421	\$1,526.32	\$1,860.42	1,860.4	405.880	\$1,454.79	\$1,454.55	
26-Dec-22	1	1,700.0	1,700.0	1,700.000	\$1,700.00	\$1,860.00	1,860.0	347.000	\$1,513.00	\$1,513.00	

On January 13, 2022 for two intervals, beginning 0625 EPT and 0630 EPT, and on January 31, 2022 for one interval, beginning 0635 EPT, there was no primary reserve shortage in the RTO Reserve Zone and the MAD Subzone. But Table 3-90 shows that the RTO synchronized reserve MCP reached \$1,700 per MWh during these three intervals even though the ORDC for synchronized reserves has a cap of \$850 per MWh and the RTO primary reserve MCP was zero. The RTO synchronized reserve MCP of \$1,700 per MWh was capped at the tariff specified overall cap on synchronized reserves by PJM. However, the price was inconsistent with the RTO synchronized reserve ORDC that has a maximum price of \$850 per MWh. Without a simultaneous primary reserve MCP that is greater than zero, the synchronized reserve MCP for the RTO Zone should not exceed \$850 per MWh. During these three intervals, PJM’s process of implementing shortage pricing for synchronized reserves was inconsistent with the tariff defined ORDC. In the MAD Subzone (Table 3-91), the uncapped MCP exceeded \$2,550 per MWh, which is the sum of the RTO synchronized reserve constraint shadow price (\$1,700 per MWh) and the MAD synchronized reserve constraint shadow price (\$850 per MWh). PJM capped the MAD synchronized reserve MCP at \$1,700 per MWh, the tariff defined overall cap for synchronized reserves. With primary reserve MCPs at zero, the uncapped MCP for MAD synchronized reserve should not exceed \$1,700 per MWh.

In 2022, there were 18 five minute intervals when the market clearing prices were set by the second step of the ORDC (\$300 per MWh) when reserves were short of the extended requirement by 0.00001 MW. This included three five-minute intervals when RTO synchronized reserves were short by 0.00001 MW and 15 five-minute intervals when RTO primary reserves were short by 0.00001 MW. These are not legitimate shortages of reserves, but instead a result of software error. When the largest contingency on the system is located in the MAD Subzone, both the MAD

¹²⁹ 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.

¹³⁰ For detailed data, see Reserve Shortages. <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/IMM_Reserve_Shortages_20230309.xlsx>.

and the RTO reserve requirements are set by this contingency, and the reserve requirement quantities for MAD and RTO are identical. In the real-time market clearing software, to avoid an issue with inaccurate prices that result from such situations, the software adds a small quantity (0.00001 MW) to the RTO reserve requirement, to differentiate the constraint from the MAD reserve requirement constraint. When the RTO reserve quantities are short by this quantity (0.00001 MW), there is no shortage of reserves compared to the reserve requirement for the RTO zone, since this was an artificially added quantity to resolve modeling issues. The market clearing prices for reserves and the LMPs should not include the penalty factor for the reserve product when the reserves are short by 0.00001 MW. The market clearing prices and LMPs during these 18 intervals are not consistent with the shortage pricing rules in the PJM tariff.

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 defining all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices.

Table 3-91 Summary of real-time MAD synchronized reserve shortage intervals: 2022¹³¹

Day (EPT)	Intervals of Shortage	Pricing Run						Dispatch Run				
		Average RTO Extended Synchronized Reserve Requirement (MW)	Average Total RTO Synchronized Reserves (MW)	Average RTO Synchronized Reserve Shortage (MW)	Average Uncapped RTO Synchronized Reserve Clearing Price (\$/MWh)	Average Capped RTO Synchronized Reserve Clearing Price (\$/MWh)	Average RTO Extended Synchronized Reserve Requirement (MW)	Average Total RTO Synchronized Reserves (MW)	Average RTO Synchronized Reserve Shortage (MW)	Average Uncapped RTO Synchronized Reserve Clearing Price (\$/MWh)	Average Capped RTO Synchronized Reserve Clearing Price (\$/MWh)	
		13-Jan-22	2	1,700.0	1,700.0	3,178.430	\$3,178.43	\$1,804.00	1,804.0	450.2	450.247	\$1,353.80
16-Jan-22	1	701.3	701.3	701.310	\$701.31	\$1,859.00	1,859.0	190.0	190.000	\$1,669.00	\$1,669.00	
27-Jan-22	2	339.8	339.8	339.835	\$339.84	\$1,778.00	1,778.0	190.0	190.000	\$1,588.00	\$1,588.00	
30-Jan-22	4	622.6	622.6	622.600	\$622.60	\$1,800.75	1,800.8	190.0	190.000	\$1,610.73	\$1,610.73	
31-Jan-22	2	1,173.3	1,173.3	1,593.040	\$1,612.60	\$1,691.00	1,691.0	283.6	283.645	\$1,407.35	\$1,407.35	
2-Mar-22	2	707.8	707.8	707.755	\$707.76	\$1,639.50	1,639.5	153.0	152.998	\$1,486.45	\$1,486.45	
12-Mar-22	1	600.0	600.0	600.000	\$600.00	\$1,825.00	1,825.0	116.9	116.856	\$1,708.10	\$1,708.10	
20-Mar-22	1	600.0	600.0	600.000	\$600.00	\$1,642.00	1,642.0	5.8	5.840	\$1,636.20	\$1,636.20	
13-Apr-22	1	600.0	600.0	600.000	\$600.00	\$1,534.70	1,534.7	84.2	84.248	\$1,450.50	\$1,450.50	
14-Apr-22	1	600.0	600.0	600.000	\$600.00	\$1,533.70	1,533.7	73.8	73.782	\$1,459.90	\$1,459.90	
16-May-22	1	600.0	600.0	600.000	\$600.00	\$1,789.00	1,789.0	108.9	108.910	\$1,680.10	\$1,680.10	
13-Jun-22	8	1,637.5	1,637.5	2,162.500	\$2,162.50	\$1,766.75	1,766.8	70.7	70.685	\$1,696.14	\$1,696.14	
27-Jun-22	1	1,378.5	1,378.5	1,378.460	\$1,378.46	\$1,792.00	1,792.0	190.0	190.000	\$1,602.10	\$1,602.10	
29-Jun-22	1	699.2	699.2	699.180	\$699.18	\$2,712.80	2,712.8	187.4	187.402	\$2,525.40	\$2,525.40	
28-Jul-22	1	1,114.4	1,114.4	1,114.410	\$1,114.41	\$1,757.00	1,757.0	190.0	190.000	\$1,567.00	\$1,567.00	
12-Oct-22	1	600.0	600.0	600.000	\$600.00	\$2,728.00	2,728.0	17.2	17.209	\$2,710.80	\$2,710.80	
23-Dec-22	21	3,404.6	1,700.0	3,404.594	\$3,404.59	\$1,860.90	1,860.9	626.9	626.857	\$1,234.06	\$1,234.06	
24-Dec-22	37	3,056.8	1,645.1	3,056.757	\$3,072.13	\$1,860.43	1,860.4	416.8	416.850	\$1,443.83	\$1,443.58	
26-Dec-22	1	3,400.0	1,700.0	3,400.000	\$3,400.00	\$1,860.00	1,860.0	347.0	346.979	\$1,513.00	\$1,513.00	

Table 3-92 Summary of real-time RTO primary reserve shortage intervals: 2022¹³²

Day (EPT)	Intervals of Shortage	Pricing Run						Dispatch Run				
		Average RTO Extended Synchronized Reserve Requirement (MW)	Average Total RTO Synchronized Reserves (MW)	Average RTO Synchronized Reserve Shortage (MW)	Average Uncapped RTO Synchronized Reserve Clearing Price (\$/MWh)	Average Capped RTO Synchronized Reserve Clearing Price (\$/MWh)	Average RTO Extended Synchronized Reserve Requirement (MW)	Average Total RTO Synchronized Reserves (MW)	Average RTO Synchronized Reserve Shortage (MW)	Average Uncapped RTO Synchronized Reserve Clearing Price (\$/MWh)	Average Capped RTO Synchronized Reserve Clearing Price (\$/MWh)	
		31-Jan-22	1	285.7	300.0	285.710	\$300.00	\$2,614.00	2,614.0	0.0	0.000	\$2,614.00
13-Jun-22	35	701.9	731.7	701.853	\$731.71	\$2,554.73	2,554.7	359.0	362.316	\$2,195.75	\$2,192.43	
23-Dec-22	71	800.3	801.0	800.285	\$801.04	\$2,695.76	2,695.8	717.4	717.439	\$1,978.32	\$1,978.32	
24-Dec-22	134	710.4	714.5	710.385	\$718.38	\$2,694.47	2,694.5	368.5	369.663	\$2,326.00	\$2,324.81	
26-Dec-22	1	850.0	850.0	850.000	\$850.00	\$2,695.00	2,695.0	983.0	982.979	\$1,712.00	\$1,712.00	

Table 3-93 Summary of real-time MAD primary reserve shortage intervals: 2022

Day (EPT)	Intervals of Shortage	Pricing Run						Dispatch Run				
		Average RTO Extended Synchronized Reserve Requirement (MW)	Average Total RTO Synchronized Reserves (MW)	Average RTO Synchronized Reserve Shortage (MW)	Average Uncapped RTO Synchronized Reserve Clearing Price (\$/MWh)	Average Capped RTO Synchronized Reserve Clearing Price (\$/MWh)	Average RTO Extended Synchronized Reserve Requirement (MW)	Average Total RTO Synchronized Reserves (MW)	Average RTO Synchronized Reserve Shortage (MW)	Average Uncapped RTO Synchronized Reserve Clearing Price (\$/MWh)	Average Capped RTO Synchronized Reserve Clearing Price (\$/MWh)	
		13-Jun-22	33	803.0	812.1	1,418.459	\$1,452.28	\$2,554.73	2,554.7	380.8	384.275	\$2,174.00
23-Dec-22	68	1,615.6	1,239.7	1,615.650	\$1,615.65	\$2,695.73	2,695.7	749.1	749.090	\$1,946.64	\$1,946.64	
24-Dec-22	123	1,329.8	1,093.7	1,329.807	\$1,340.11	\$2,695.13	2,695.1	401.4	402.722	\$2,293.71	\$2,292.41	
25-Dec-22	1	300.0	300.0	300.000	\$300.00	\$2,572.00	2,572.0	69.0	32.873	\$2,503.00	\$2,539.10	
26-Dec-22	1	1,700.0	1,275.0	1,700.000	\$1,700.00	\$2,695.00	2,695.0	983.0	982.979	\$1,712.00	\$1,712.00	

131 For detailed data, see Reserve Shortages. <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/IMM_Reserve_Shortages_20230309.xlsx>.

132 For detailed data, see Reserve Shortages. <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/IMM_Reserve_Shortages_20230309.xlsx>.

Table 3-94 Real-time RTO 30-minute reserve shortage intervals: 2022

Interval (EPT)	Pricing Run					Dispatch Run				
	RTO Extended 30-Minute Reserve Requirement (MW)	Total RTO 30-Minute Reserves (MW)	RTO 30-Minute Reserve Shortage (MW)	Uncapped RTO 30-Minute Reserve Clearing Price (\$/MWh)	Capped RTO 30-Minute Reserve Clearing Price (\$/MWh)	RTO Extended 30-Minute Reserve Requirement (MW)	Total RTO 30-Minute Reserves (MW)	RTO 30-Minute Reserve Shortage (MW)	Uncapped RTO 30-Minute Reserve Clearing Price (\$/MWh)	Capped RTO 30-Minute Reserve Clearing Price (\$/MWh)
24-Dec-22 08:05	3,190.0	3,091.1	98.893	\$300.00	\$300.00	3,190.0	3,091.1	98.893	\$300.00	\$300.00
24-Dec-22 08:10	3,190.0	3,015.6	174.352	\$300.00	\$300.00	3,190.0	3,015.6	174.352	\$300.00	\$300.00
24-Dec-22 08:15	3,190.0	3,000.0	190.000	\$774.59	\$774.59	3,190.0	3,000.0	190.000	\$774.59	\$774.59
24-Dec-22 08:20	3,190.0	3,063.7	126.334	\$300.00	\$300.00	3,190.0	3,063.7	126.334	\$300.00	\$300.00
24-Dec-22 08:25	3,190.0	3,172.1	17.909	\$300.00	\$300.00	3,190.0	3,172.1	17.909	\$300.00	\$300.00
24-Dec-22 08:30	3,190.0	3,000.0	190.000	\$418.63	\$418.63	3,190.0	3,000.0	190.000	\$418.63	\$418.63
24-Dec-22 08:35	3,190.0	3,000.0	190.000	\$763.04	\$763.04	3,190.0	3,000.0	190.000	\$763.04	\$763.04
24-Dec-22 08:40	3,190.0	3,025.7	164.333	\$300.00	\$300.00	3,190.0	3,025.7	164.333	\$300.00	\$300.00
24-Dec-22 08:45	3,190.0	3,000.0	190.000	\$615.04	\$615.04	3,190.0	3,000.0	190.000	\$591.54	\$591.54
24-Dec-22 08:50	3,190.0	3,033.2	156.830	\$300.00	\$300.00	3,190.0	3,033.2	156.830	\$300.00	\$300.00
24-Dec-22 09:00	3,190.0	3,000.0	190.000	\$301.62	\$301.62	3,190.0	3,000.0	190.000	\$301.54	\$301.54
24-Dec-22 09:10	3,190.0	2,868.7	321.261	\$850.00	\$850.00	3,190.0	2,868.7	321.261	\$850.00	\$850.00
24-Dec-22 09:15	3,190.0	3,000.0	190.000	\$678.08	\$678.08	3,190.0	3,000.0	190.000	\$678.08	\$678.08
24-Dec-22 09:25	3,190.0	3,000.0	190.000	\$352.73	\$352.73	3,190.0	3,000.0	190.000	\$352.73	\$352.73
24-Dec-22 09:30	3,190.0	3,058.5	131.458	\$300.00	\$300.00	3,190.0	3,068.1	121.948	\$300.00	\$300.00
24-Dec-22 09:40	3,190.0	3,000.0	190.000	\$365.12	\$365.12	3,190.0	3,000.0	190.000	\$364.86	\$364.86

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.¹³³ The system marginal price cap should be included in the PJM tariff and Operating Agreement.

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 is the result 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 the 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 LMPs at a pricing node could still exceed \$3,700 per MWh.

Table 3-95 shows number of five minute intervals in the real time market where the SMP was capped for each year since 2019. During Elliott, PJM administratively capped SMP at \$3,700 per MWh in the pricing run for 51 five minute intervals.

¹³³ O.A. Schedule 1, Section 3.2.3A(d) and Section 3.2.3A.001(c).

Table 3-95 Number of Five minute intervals with capped SMP: January 2019 through December 2022

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

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

Accuracy of Reserve Measurement

The definition of a shortage of synchronized and primary reserves is based on the measured and estimated levels of load, generation, interchange, demand response, and reserves from the real-time SCED software. The definition of such shortage also includes discretionary operator inputs to the ASO (Ancillary Service Optimizer) or RT SCED software, such as operator load bias. For shortage pricing to be accurate, there must be accurate measurement of real-time reserves. That does not appear to be the case at present in PJM, but there does not appear to be any reason that PJM cannot accurately measure reserves. Without accurate measurement of reserves on a minute by minute basis, system operators cannot know with certainty that there is a shortage condition and a reliable trigger for five minute shortage pricing does not exist. The benefits of five minute shortage pricing are based on the assumption that a shortage can be precisely and transparently defined.¹³⁴ PJM cannot accurately measure or price reserves due to the inaccuracy of its generator models. PJM's commitment and dispatch models rely on generator data to properly commit and dispatch generators. Generator data includes offers and parameters. When the models do not properly account for the different generator characteristics, both PJM dispatchers and generators have to make simplifications and assumptions using the tools available. Most of these actions taken by generators and by PJM dispatchers are not transparent. PJM manuals do not provide clarity regarding what actions generators can take when the PJM models and tools do not reflect their operational characteristics and PJM manuals do not provide sufficient clarity regarding

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

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

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

During Elliott, PJM cleared reserves on resources that failed to start, did not have fuel, or were unavailable for other reasons. The extent of shortage pricing on December 23 and 24, 2022, would have been greater if PJM had accurate data on generator availability.

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 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.

¹³⁴ See Comments of the Independent Market Monitor for PJM, Docket No. RM15-24-000 (December 1, 2015) at 9.

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.¹³⁵

When transmission constraints exist, local markets are created in which ownership that is typically significantly more concentrated than the overall energy market. PJM offer capping rules that limit the exercise of local market power were generally effective in preventing the exercise of market power in 2022, although there are issues with the application of market power mitigation for resources whose owners fail the TPS test that permit local market power to be exercised even when mitigation rules are applied. These issues include the lack of a method for consistently determining the cheaper of the cost and price schedules and the lack of rules requiring that cost-based offers equal short run marginal costs.

PJM HHI Results

Hourly HHIs indicate that by FERC standards, the PJM energy market in 2022 was unconcentrated on average (Table 3-96).¹³⁶ 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 3-96 Real-time hourly aggregate energy market HHI: 2021 and 2022

HHI Statistic	Hourly Market HHI (2021)	Hourly Market HHI (2022)
Average	742	700
Minimum	532	554
Maximum	1115	1012
Highest market share (One hour)	27%	26%
Average of the highest hourly market share	19%	18%
# Hours	8,760	8,760
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-97 includes HHI values by supply curve segment, including base, intermediate and peaking plants in 2021 and 2022. On average, ownership in the baseload segment was unconcentrated, in the intermediate segment was moderately concentrated, and in the peaking segment was highly concentrated.¹³⁷ High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal in the aggregate market.

Table 3-97 Real-time hourly energy market HHI by generation segment: 2021 and 2022

	2021			2022		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	636	795	1148	580	730	1050
Intermediate	561	1196	6166	727	1715	9818
Peak	662	5956	10000	714	6282	10000

¹³⁵ See *Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement*, 77 FERC ¶ 61,263 mimeo at 80 (1996).

¹³⁶ The HHI calculations use actual real time settled generation data for each unit in PJM. Each unit's output is assigned to the supplier that is responsible for offering the unit in the energy market.

¹³⁷ A unit is classified as base load if it runs for 50 percent of hours or more, as intermediate if it runs for less than 50 percent but greater than or equal to 10 percent of hours, and as peak if it runs for less than 10 percent of hours.

Figure 3-69 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in 2022.¹³⁸

Figure 3-69 Real-time ICAP distribution by fuel and segment: 2022¹³⁹

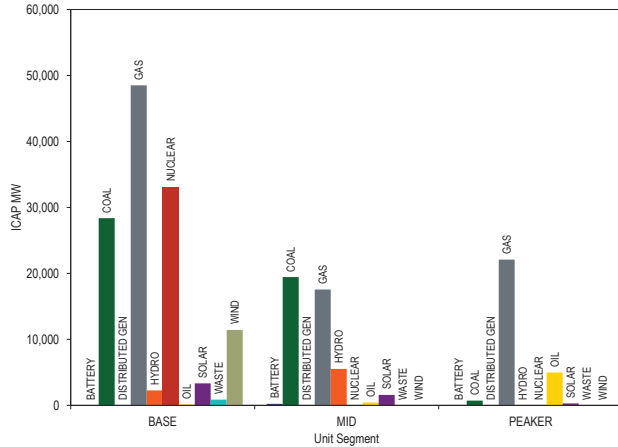


Figure 3-70 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking from 2014 through 2022. Figure 3-70 shows that the total ICAP of coal fired units in PJM classified as baseload generally decreased from 2014 through 2022, and the total ICAP of gas fired units in PJM classified as baseload generally increased from 2014 through 2022. In the first nine months of 2019, the ICAP of gas fired units classified as baseload exceeded the ICAP of coal fired units classified as baseload for the first time. The ICAP of coal fired units classified as baseload increased in 2021 and decreased in 2022.

Figure 3-70 Real-time annual gas and coal unit segment classification: 2014 through 2022

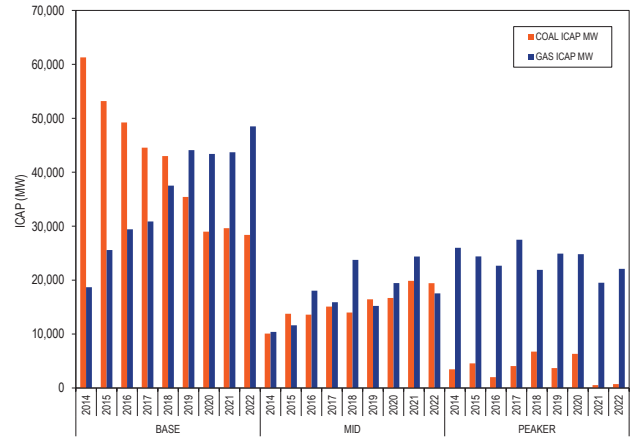
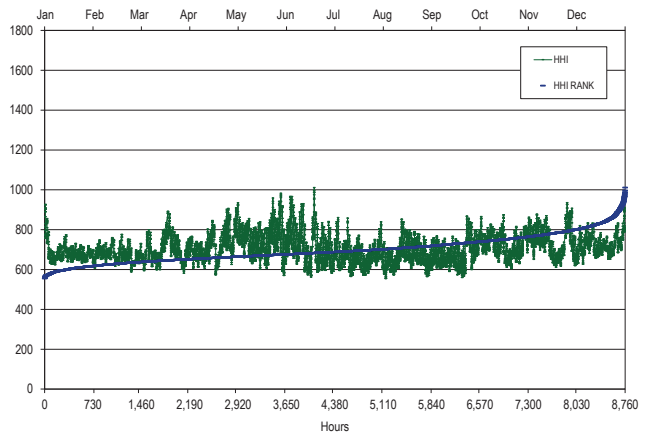


Figure 3-71 presents the hourly HHI values in chronological order and an HHI duration curve for 2022.

Figure 3-71 Real-time hourly aggregate energy market HHI: January through December, 2022



Market Based Rates

Participation in the PJM market using offers that exceed costs requires market based rate authority approved by FERC.¹⁴⁰ 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

¹³⁸ 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 effective load carrying capability.

¹³⁹ The units classified as Distributed Gen are buses within Electric Distribution Companies (EDCs) that are modeled as generation buses to accurately reflect net energy injections from distribution level load buses. The modeling change was the outcome of the Net Energy Metering Task Force stakeholder group in July, 2012. See PJM. "Net Energy Metering Senior Task Force (NEMSTF) 1st Read - Final Report and Proposed Manual Revisions," (June 28, 2012) <<http://www.pjm.com/-/media/committees-groups/task-forces/nemstf/postings/20120628-first-read-item-04-nemstf-report-and-proposed-manual-revisions.ashx>>.

¹⁴⁰ 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).

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.¹⁴¹

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 2020. The applicable study period for the June 2020 filings, ran from December 1, 2017, to November 30, 2018. 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 new triennial review filings for nontransmission owning utilities in PJM will be due in June 2023. The applicable study period for the June 2023 filings runs from December 1, 2020, to November 30, 2021.

The MMU has recommended since 2015 that changes to the offer capping process for the energy market are needed to ensure effective market power mitigation of units that fail the TPS test. With these results and the supporting evidence, the MMU challenged the rebuttable presumption of sufficient market power mitigation for the June 2020 and December 2022 triennial review filings by generating unit owners in PJM. The MMU recommended that generators should not be relying on PJM market power mitigation 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.¹⁴² In 2021, FERC issued orders requiring review of the adequacy of the market power mitigation rules and their implementation in the capacity and energy markets.¹⁴³ ¹⁴⁴ FERC addressed the capacity market Market Seller Offer cap later in 2021.¹⁴⁵

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.”¹⁴⁶ ¹⁴⁷

FERC applies tests set forth in the 1996 Merger Policy Statement.¹⁴⁸ ¹⁴⁹ 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 2010.¹⁵⁰ Following the 1992 Guidelines, FERC applies a five step framework, which includes: defining the market; analyzing market concentration; analyzing mitigative effects of new entry; assessing efficiency gains; and assessing viability of the parties without a merger. FERC also evaluates a Competitive Analysis Screen.

The MMU reviews proposed mergers based on analysis of the impact of the merger or acquisition on market power given actual market conditions. The analysis includes use of the three pivotal supplier test results in the real-time energy market. The MMU’s review ensures that mergers are evaluated based on their impact on local market power in the PJM energy market using

¹⁴¹ *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”).

¹⁴² 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).

¹⁴³ See 175 FERC ¶ 61,231 (2021).

¹⁴⁴ See 174 FERC ¶ 61,212 (2021).

¹⁴⁵ See 176 FERC ¶ 61,137 (2021), *reh’g denied*, 178 FERC ¶ 61,121 (2022), *appeal pending*.

¹⁴⁶ 18 U.S.C. § 824b.

¹⁴⁷ 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).

¹⁴⁸ 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).

¹⁴⁹ 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.

¹⁵⁰ See 138 FERC ¶ 61,109 (2012).

actual observed market conditions, actual binding constraints and actual congestion results. This is in contrast to the typical merger filing that uses predefined local markets based on historical conditions that no longer exist rather than the actual local markets based on current and potential market conditions. The MMU files comments including such analyses.¹⁵¹ The MMU has proposed that FERC adopt this approach when evaluating mergers in PJM.¹⁵² 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.¹⁵³

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

The MMU also reviews transactions that involve ownership changes of PJM generation resources that are submitted to the Commission pursuant to section 203 of the Federal Power Act. Table 3-98 shows transactions that involved entire resources that were completed in 2022, as reported to the Commission. Table 3-99 shows transactions that involved transfers of partial unit ownership that were completed in 2022, as reported to the Commission.¹⁵⁴

Table 3-98 Completed transfers of entire resources: 2022

Generator or Generation Owner Name	From	To	Transaction Completion Date	Docket
Archaea Generation	Archaea Energy, Inc.	BP Products North America Inc.	December 22, 2022	EC23-18
Backbone Mountain Windpower LLC, Meyerdale Windpower LLC, Mill Run Windpower LIC, Somerset Windpower LLC, Watmart Wind Farm LLC	GlidePath Power Solutions LLC	Sequitur Renewables, LLC	October 30, 2022	EC22-101
Cambria Wind, LLC	Oppidum Capital, S.L.	Boreas Energia, S.L.	September 27, 2022	EC22-95
Rolling Hills Generating, LLC	Arclight Capital Partners	LSP Development	September 16, 2022	EC22-76
Crete Energy Venture, LLC, Lincoln Generating Facility LLC	Eastern LC, LLC	Earthrise Energy, PBC	September 6, 2022	EC22-75
Cardinal Station Unit 1	AEP Generation Resources Inc.	Buckeye Power, Inc	August 1, 2022	EC22-50
INGENCO Wholesale Power, LLC	Collegiate Clean Energy LLC	Archaea Infrastructure LLC	July 1, 2022	EC22-66
Big Savage, Highland North, Patton Wind	BlackRock, Inc.	Vitol Inc.	June 24, 2022	EC22-56
Energy Center Dover	DCO Energy	Groupe BPCE	May 26, 2022	EC22-37
Glatfelter Cogen	Lindsay Goldberg	HIG Capital	May 25, 2022	EC22-49
Energy Center Paxton	Clearway Energy Inc	KKR & Co. Inc.	May 1, 2022	EC22-16
PSEG Fossil Portfolio	PSEG	Arclight Capital Partners	February 18, 2022	EC21-128
Exelon Generation	Exelon Corp	Constellation Energy Generation	February 1, 2022	EC21-57

Table 3-99 Completed transfers of partial ownership of resources: 2022

Generator or Generation Owner Name	From	To	Transaction Completion Date	Docket
Uniper Global Commodities North America, LLC (99%)	Fortum Oyj	The Federal Republic of Gemany	December 21, 2022	EC23-12
Black Rock Wind Force LLC (50%)	Clearway Energy Group	TotalEnergies Renewabls USA, LLC	September 12, 2022	EC22-84
Chambers Cogen (40%)	I Squared Capital Advisors LLC	Starwood Energy Group	March 21, 2022	EC22-25
CPV Fairview (25%)	Apollo Global Management	DL Energy Co	March 14, 2022	EC22-31

The MMU has also reached agreements to mitigate market power in cases where market power concerns have been identified.¹⁵⁵ 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.

¹⁵¹ 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).

¹⁵² See Comments of the Independent Market Monitor for PJM, Docket No. RM16-21 (Dec. 12, 2016).

¹⁵³ 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).

¹⁵⁴ The transaction completion date is based on the notices of consummation submitted to the Commission.

¹⁵⁵ 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.

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.¹⁵⁶ 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.¹⁵⁷ Aggregate market power should be mitigated in the PJM day-ahead and real-time markets when the three pivotal supplier test is failed.

¹⁵⁶ Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 104–117.

¹⁵⁷ One supplier, Exelon Generating Company, LLC, is partially mitigated for aggregate market power through a settlement agreement with the MMU filed December 30, 2021 and approved by the Maryland Public Service Commission as a condition of its merger. *In the Matter of the Merger of Exelon Corporation and Constellation Energy Group, Inc.*, Order No. 90084, Maryland PSC Case No. 9271 (February 22, 2022). Order No. 90084 replaces the original 10 year settlement in this case included as a condition in Order No. 84698, issued February 17, 2012, which approved the merger between Exelon and Constellation Energy Group.

Day-Ahead 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 3-72 shows the number of days in 2021 and 2022 with one aggregate pivotal supplier, two aggregate jointly pivotal suppliers, and three aggregate jointly pivotal suppliers for the day-ahead energy market. Multiple suppliers were singly pivotal on the summer peak days of 2021 and 2022. One supplier was singly pivotal on February 15, 2021, on July 6, 2021, on three days in August 2021, on June 15 and 16, 2022, and on December 25, 2022. Two suppliers were jointly pivotal on 116 days in 2021 and on 82 days in 2022. Three suppliers were jointly pivotal on 286 days in 2021 and 245 days in 2022, despite average HHIs at persistently unconcentrated levels. In 2021 and 2022, the highest levels of aggregate market power occurred in the third quarter, PJM's summer peak load season. Outside the summer months, the frequency of pivotal suppliers increased on high demand days in February 2021, January 2022, and December 2022.

Figure 3–72 Days with pivotal suppliers and numbers of pivotal suppliers in the day-ahead energy market by quarter

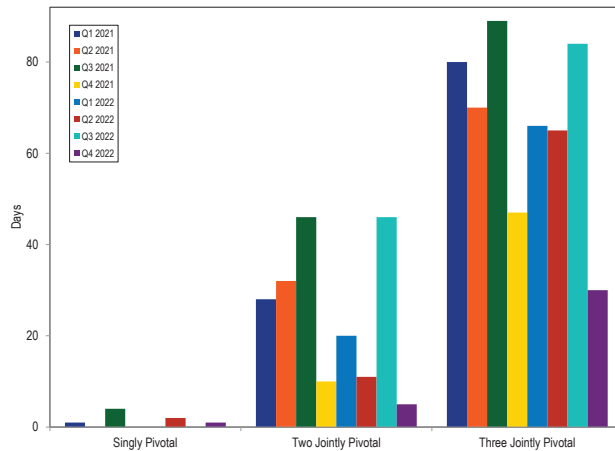


Table 3-100 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the day-ahead energy market in 2022. All of the top 10 suppliers were one of three pivotal suppliers on at least 122 days in 2022 (33.4 percent of the days).

Table 3–100 Day-ahead market pivotal supplier frequency: 2022

Pivotal Supplier Rank	Days Singly Pivotal		Days Jointly Pivotal with One Other Supplier		Days Jointly Pivotal with Two Other Suppliers	
	Days Pivotal	Percent of Days	Days Pivotal	Percent of Days	Days Pivotal	Percent of Days
1	3	0.8%	77	21.1%	236	64.7%
2	2	0.5%	75	20.5%	229	62.7%
3	0	0.0%	62	17.0%	235	64.4%
4	0	0.0%	59	16.2%	241	66.0%
5	0	0.0%	48	13.2%	192	52.6%
6	0	0.0%	19	5.2%	147	40.3%
7	0	0.0%	17	4.7%	148	40.5%
8	0	0.0%	17	4.7%	121	33.2%
9	0	0.0%	9	2.5%	126	34.5%
10	0	0.0%	7	1.9%	122	33.4%

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.¹⁵⁸ If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners who have been identified as having local market power. Offer capping is designed to set offers at competitive levels. Competitive offers are defined to be cost-based energy offers. In the PJM energy market, units are required to submit cost-based energy offers, defined by fuel cost policies, and have the option to submit market-based, also called price-based, offers. Units are committed and dispatched on price-based offers, if offered, as the default offer. When a unit that submits both cost-based and price-based offers is mitigated to its cost-based offer by PJM, it is considered offer capped. A unit that submits only cost-based offers, or that requests PJM to dispatch it on its cost-based offer, is not considered offer capped.

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

TPS Test Statistics for Local Market Power

The TPS test in the energy market defines whether one, two or three suppliers are jointly pivotal in a defined local market. The TPS test is applied when the system solution indicates that out of merit resources are needed to relieve a transmission constraint. The TPS test result for a constraint

for a specific interval indicates whether a supplier failed or passed the test for that constraint for that interval. A failed test indicates that the resource owner has structural market power.

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

¹⁵⁸ 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>.

In 2022 in the real-time energy market, the 500 kV system, ten zones, and MISO experienced congestion resulting from one or more constraints binding for 100 or more hours, or resulting from a binding interface constraint (Table 3-101).¹⁵⁹ Table 3-101 shows that the 500 kV system, five zones and 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 2013 through 2022. Four 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 2013 through 2022.¹⁶⁰

Table 3-101 Real-time congestion hours resulting from one or more constraints binding for 100 or more hours: 2013 through 2022

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
500 kV System	1,774	2,055	665	804	944	1,112	4,470	2,217	556	1,021
ACEC	104	0	197	439	0	500	108	0	0	0
AEP	943	2,172	1,385	400	469	1,301	535	1,133	735	500
APS	0	170	167	0	265	246	191	322	718	0
ATSI	101	310	117	0	164	932	0	0	0	237
BGE	440	2,393	4,262	5,501	1,506	2,496	690	2,929	1,176	462
COMED	1,763	1,908	2,516	3,587	1,359	724	343	761	634	1,307
DAY	0	0	0	0	0	0	0	0	181	0
DEOK	0	0	112	0	0	0	0	0	0	139
DLCO	0	223	368	0	0	0	0	0	0	0
DOM	547	0	837	459	441	136	197	896	254	2,029
DPL	213	1,604	1,539	1,976	675	1,049	0	106	144	0
DUKE	0	0	0	0	0	0	0	0	0	0
DUQ	0	0	0	0	0	0	0	0	0	0
EKPC	0	0	0	0	0	200	0	0	0	0
EXT	0	0	0	0	788	0	0	0	0	0
JCPLC	0	0	0	0	0	0	0	0	0	0
MEC	0	0	111	0	116	755	465	1,042	191	1,232
MISO	4,761	4,755	3,988	3,946	4,450	4,106	4,837	3,731	1,918	7,561
NYISO	167	143	419	1,074	332	0	0	0	0	0
OVEC	0	0	0	0	0	0	0	0	0	0
PE	176	4,096	1,553	141	1,952	1,308	1,972	2,302	328	1,520
PECO	244	884	690	751	1,374	719	468	306	480	3,072
PEPCO	100	0	0	0	0	0	0	0	0	0
PPL	0	107	135	470	1,168	295	1,044	575	722	2,072

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 ACEC, 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 The constraint data for September 2021 through December 2022 is based on the dispatch run.

In the PJM Day-Ahead Energy Market, the TPS test is performed in PROBE, as part of the unit commitment process. Table 3-102 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing the TPS test for the interface constraints in the PJM Day-Ahead Energy Market.

Table 3-102 Day-ahead three pivotal supplier test details for interface constraints: 2022

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005	Peak	223	459	23	0	23
	Off Peak	298	1,349	36	34	2
AEP - DOM	Peak	505	501	18	3	15
	Off Peak	558	359	15	1	14
AP South	Peak	450	809	26	9	17
	Off Peak	524	1,277	27	12	15
BC Pepco	Peak	NA	NA	NA	NA	NA
	Off Peak	646	1,061	19	0	19
Bedington - Black Oak	Peak	91	277	25	19	6
	Off Peak	161	288	25	14	11
Central	Peak	NA	NA	NA	NA	NA
	Off Peak	504	279	20	0	20
East	Peak	127	2,194	20	20	0
	Off Peak	NA	NA	NA	NA	NA
PA Central	Peak	170	226	11	1	10
	Off Peak	160	224	9	1	8
West	Peak	767	2,515	35	28	7
	Off Peak	657	3,089	34	30	4

Table 3-103 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. The TPS test was not applied for two of 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.

Table 3-103 shows that two of the top ten binding constraints in the day-ahead energy market were not tested for local market power in 2022 (Mountain and Ramapo). 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.

¹⁶¹ See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Section 5.2.6 Rev. 119 (March 23, 2022).

Table 3-103 Day-ahead three pivotal supplier test details for top 10 congested constraints: 2022

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Nottingham	Peak	314	414	28	13	15
	Off Peak	196	335	24	13	12
Mountain	Peak	0	0	0	0	0
	Off Peak	0	0	0	0	0
Boonetown - South Reading	Peak	160	115	7	0	7
	Off Peak	102	107	6	0	6
Easton - Emuni	Peak	16	7	1	0	1
	Off Peak	8	4	1	0	1
Prest - Tibb	Peak	22	36	6	0	6
	Off Peak	19	27	5	0	4
Haumesser Road - Steward	Peak	123	85	6	0	6
	Off Peak	111	57	4	0	4
Allen - R.P. Mone	Peak	234	168	15	2	13
	Off Peak	293	207	15	2	13
Cumberland - Juniata	Peak	137	82	11	0	10
	Off Peak	88	56	7	0	7
Lenox - North Meshoppen	Peak	72	45	9	1	8
	Off Peak	69	33	7	1	6
Ramapo (ConEd) - S Mahwah (RECO)	Peak	0	0	0	0	0
	Off Peak	0	0	0	0	0

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 2022.¹⁶² 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 3-104 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 3-105 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 3-104 and Table 3-105 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.

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.

Table 3-104 Real-time three pivotal supplier test details for interface constraints: 2022

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	364	440	14	3	10
	Off Peak	402	391	14	2	12
AEP - DOM	Peak	295	201	8	0	7
	Off Peak	371	314	10	0	9
AP South	Peak	591	740	14	2	11
	Off Peak	652	656	13	2	11
Bedington - Black Oak	Peak	184	174	12	2	10
	Off Peak	175	154	11	1	10
Eastern	Peak	472	621	15	4	11
	Off Peak	548	602	14	1	13
PA Central	Peak	219	505	8	1	7
	Off Peak	161	571	7	1	6
Western	Peak	856	580	14	0	14
	Off Peak	654	884	12	4	8

Table 3-105 Real-time three pivotal supplier test details for top 10 congested constraints: 2022

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Nottingham	Peak	117	142	13	3	10
	Off Peak	90	127	11	3	9
Prest - Tibb	Peak	25	10	2	0	2
	Off Peak	24	11	2	0	2
Boonetown - South Reading	Peak	52	64	3	0	3
	Off Peak	27	43	3	0	3
Shadeland - Lafayette South	Peak	22	27	3	0	3
	Off Peak	18	25	3	0	3
Lenox - North Meshoppen	Peak	11	16	3	0	2
	Off Peak	8	17	2	0	2
Lackawanna	Peak	91	94	4	0	4
	Off Peak	72	208	4	0	4
Northwest Tap - Purdue	Peak	16	28	2	0	2
	Off Peak	20	28	2	0	2
Brambleton - Evergreen Mills	Peak	61	50	3	0	3
	Off Peak	57	66	4	0	4
7713 - Crescent Ridge	Peak	14	23	2	0	2
	Off Peak	11	21	2	0	2
Greys Point - Harmony Village	Peak	29	32	1	0	1
	Off Peak	33	34	1	0	1

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, whose owners fail the TPS test, are also switched to the cost-based offer if it is cheaper than the price-based offer.

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.

Units committed in the day-ahead market often fail the TPS test in the real-time market when they are redispached 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 3-106 shows that 1.3 percent of unit hours that cleared the day-ahead market on their price based offer were switched to cost in real-time. Table 3-106 shows that 10.9 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 3-106 Day-ahead units committed on price-based offers that cleared real-time: 2021 and 2022

Year	Day Ahead Price Based Unit Hours That Cleared Real-Time			Percent Day Ahead Price Based Unit Hours That Cleared Real-Time	
	On Cost	On Price	On Price and Failed TPS Test	On Price and Failed TPS Test	
				On Cost	Failed TPS Test
2021	27,559	2,703,543	231,545	1.0%	8.5%
2022	32,749	2,482,370	275,112	1.3%	10.9%

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 3-107 and Table 3-108 provide, for the identified constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping in the real-time energy market. Tests where there was at least one offline unit or an online unit eligible for offer capping are considered tests that could have resulted in offer capping. PJM operators also manually commit units for reliability reasons other than providing relief to a binding constraint. Manual commitments are offer capped along with resources that fail the TPS test.

Table 3-107 Summary of real-time three pivotal supplier tests applied for interface constraints: 2022

Constraint	Period	Total Tests Applied	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
			Resulted in Offer Capping	Have Resulted in Offer Capping		Tests Resulted in Offer Capping	Offer Capping	
5004/5005 Interface	Peak	1,022	1,020	100%	16	2%	2%	
	Off Peak	1,265	1,265	100%	21	2%	2%	
AEP - DOM	Peak	1,000	999	100%	40	4%	4%	
	Off Peak	1,319	1,318	100%	31	2%	2%	
AP South	Peak	3,616	3,615	100%	76	2%	2%	
	Off Peak	4,576	4,567	100%	47	1%	1%	
Bedington - Black Oak	Peak	2,496	2,486	100%	36	1%	1%	
	Off Peak	6,665	6,640	100%	89	1%	1%	
Eastern	Peak	1,075	1,060	99%	56	5%	5%	
	Off Peak	871	857	98%	21	2%	2%	
PA Central	Peak	771	663	86%	0	0%	0%	
	Off Peak	556	509	92%	8	1%	2%	
Western	Peak	228	228	100%	3	1%	1%	
	Off Peak	85	85	100%	0	0%	0%	

Table 3-108 Summary of real-time three pivotal supplier tests applied for top 10 congested constraints: 2022

Constraint	Period	Total Tests that Could Have		Percent Total Tests that Could		Tests Resulted in Offer		Capping as Percent of Tests that Could Have Resulted in	
		Total Tests Applied	Resulted in Offer Capping	Have Resulted in Offer Capping	Resulted in Offer Capping	Percent Tests Resulted in Offer Capping	Offer Capping	Offer Capping	
Nottingham	Peak	67,789	66,685	98%	704	1%	1%		
	Off Peak	45,589	44,546	98%	455	1%	1%		
Prest - Tibb	Peak	4,483	205	5%	0	0%	0%		
	Off Peak	8,749	147	2%	0	0%	0%		
Boonetown - South Reading	Peak	21,797	9,011	41%	31	0%	0%		
	Off Peak	5,540	1,565	28%	3	0%	0%		
Shadeland - Lafayette South	Peak	12,002	9,757	81%	0	0%	0%		
	Off Peak	16,891	13,932	82%	0	0%	0%		
Lenox - North Meshoppen	Peak	18,585	9,950	54%	6	0%	0%		
	Off Peak	11,994	4,747	40%	11	0%	0%		
Lackawanna	Peak	8,179	5,064	62%	8	0%	0%		
	Off Peak	6,900	3,871	56%	2	0%	0%		
Northwest Tap - Purdue	Peak	5,851	1,619	28%	0	0%	0%		
	Off Peak	7,847	2,411	31%	0	0%	0%		
Brambleton - Evergreen Mills	Peak	15,584	5,596	36%	36	0%	1%		
	Off Peak	8,088	3,973	49%	47	1%	1%		
7713 - Crescent Ridge	Peak	8,668	389	4%	0	0%	0%		
	Off Peak	2,960	172	6%	0	0%	0%		
Greys Point - Harmony Village	Peak	8,887	8,035	90%	30	0%	0%		
	Off Peak	13,207	12,392	94%	53	0%	0%		

Offer Capping for Local Market Power

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

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

In both the day-ahead and real-time energy markets, generators with market power have the ability to evade mitigation by using varying markups in their price-based offers, offering different operating parameters in their price-based and cost-based offers, and using different fuels in their price-based and cost-based offers. These issues can be resolved by simple rule changes.

When an owner fails the TPS test, the units offered by the owner that are committed to provide relief are committed on the cheaper of cost-based or price-based offers. In the day-ahead energy market, PJM commits a unit on the schedule that results in the lower overall system production cost. Under the current approach, operating parameters are tied to the cost parameters (startup cost, no load cost, and incremental energy offer). The day-ahead energy market selects which schedule to use for a resource that failed the TPS test based on its objective of clearing resources to meet the total demand at the lowest bid production cost for the system over the 24 hour period. True least system production cost can be achieved using an approach in which operating parameters and offer parameters are independently evaluated.

In the real-time energy market, PJM uses a dispatch cost formula to compare price-based offers and cost-based offers to select the cheaper offer.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. Figure 3-73 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 3-73 Offers with varying markups at different MW output levels

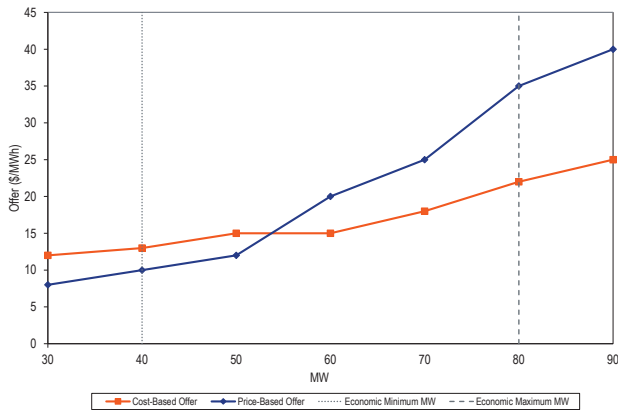


Table 3-109 shows the number and percent of unit schedule hours, by month, when unit offers included crossing curves in the PJM Day-Ahead and Real-Time Energy Markets in 2022. The analysis only includes units that offer both price-based and cost-based offers. Units in PJM are only required to submit cost-based offers, but they may elect to offer price-based offers.

¹⁶⁵ See OA Schedule 1 § 6.4.1(g).

Table 3-109 Units offered with crossing curves: January through December, 2022

2022	Day-Ahead			Real-Time		
	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	80,695	852,120	9.5%	69,275	799,250	8.7%
Feb	71,587	778,104	9.2%	60,587	713,491	8.5%
Mar	81,695	873,766	9.3%	62,118	738,675	8.4%
Apr	86,781	848,640	10.2%	64,661	682,293	9.5%
May	102,572	875,112	11.7%	78,010	750,802	10.4%
Jun	98,680	832,128	11.9%	82,437	770,067	10.7%
Jul	115,403	858,624	13.4%	102,174	814,863	12.5%
Aug	120,562	857,832	14.1%	104,894	810,338	12.9%
Sep	113,028	827,616	13.7%	97,403	743,300	13.1%
Oct	105,114	848,664	12.4%	78,744	680,764	11.6%
Nov	88,644	813,839	10.9%	63,481	671,225	9.5%
Dec	84,884	834,000	10.2%	68,332	743,994	9.2%
Total	1,149,645	10,100,445	11.4%	932,116	8,919,062	10.5%

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 3-110 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 3-110 Units offered with lower minimum run time on price compared to cost and with positive markup: January through December, 2022

2022	Day-Ahead			Real-Time		
	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	5,821	852,120	0.7%	4,948	799,250	0.6%
Feb	4,838	778,104	0.6%	4,158	713,491	0.6%
Mar	7,678	873,766	0.9%	6,523	738,675	0.9%
Apr	8,662	848,640	1.0%	7,171	682,293	1.1%
May	10,132	875,112	1.2%	9,449	750,802	1.3%
Jun	9,897	832,128	1.2%	9,599	770,067	1.2%
Jul	10,656	858,624	1.2%	10,578	814,863	1.3%
Aug	11,416	857,832	1.3%	11,337	810,338	1.4%
Sep	10,680	827,616	1.3%	9,117	743,300	1.2%
Oct	11,616	848,664	1.4%	9,049	680,764	1.3%
Nov	10,415	813,839	1.3%	8,868	671,225	1.3%
Dec	10,778	834,000	1.3%	9,122	743,994	1.2%
Total	112,589	10,100,445	1.1%	99,919	8,919,062	1.1%

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 3-74 shows an example of offers from a unit that has a positive markup and a price-based offer with a lower economic minimum MW than the cost-based offer. Keeping the startup cost, Minimum Run Time and no load cost constant between the price-based offer and cost-based offer, the dispatch cost for this unit is lower on the price-based offer than on the cost-based offer solely as a result of the lower economic minimum MW. However, the price-based offer includes a positive markup and could result in setting the market price at a noncompetitive level even after the resource owner fails the TPS test.

Figure 3-74 Offers with a positive markup but different economic minimum MW

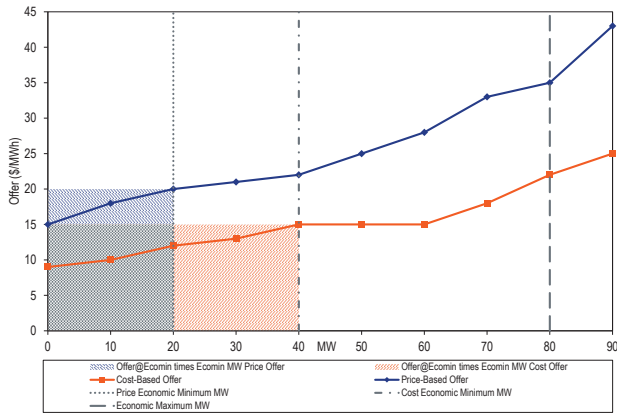


Table 3-111 shows the number and percent of unit schedule hours when units offered lower economic minimum MW in price-based offers than in cost-based offers while having a positive markup in the price-based offer.

Table 3-111 Units offered with lower economic minimum MW on price compared to cost and with positive markup: January through December, 2022

2022	Day-Ahead			Real-Time		
	Number of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Number of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost
Jan	0	852,120	0.0%	0	799,250	0.0%
Feb	0	778,104	0.0%	0	713,491	0.0%
Mar	0	873,766	0.0%	0	738,675	0.0%
Apr	0	848,640	0.0%	0	682,293	0.0%
May	0	875,112	0.0%	0	750,802	0.0%
Jun	336	832,128	0.0%	312	770,067	0.0%
Jul	264	858,624	0.0%	264	814,863	0.0%
Aug	336	857,832	0.0%	333	810,338	0.0%
Sep	216	827,616	0.0%	168	743,300	0.0%
Oct	0	848,664	0.0%	0	680,764	0.0%
Nov	0	813,839	0.0%	0	671,225	0.0%
Dec	192	834,000	0.0%	112	743,994	0.0%
Total	1,344	10,100,445	0.0%	1,189	8,919,062	0.0%

In the case of dual fuel units, if the price-based offer uses a cheaper fuel and the cost-based offer uses a more expensive fuel, the price-based offer will appear to be cheaper even when it includes a markup. Figure 3-75 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 3-112 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 2022.

Figure 3-75 Dual fuel unit offers

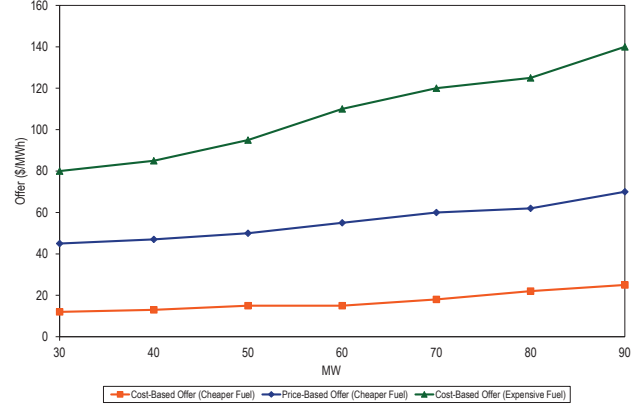


Table 3-112 Dual fuel unit offers with cost-based offers exceeding price-based offers (negative markup) but different fuel: January through December, 2022

2022	Day-Ahead			Real-Time		
	Number of Unit Hours With Negative Markup And No Matching Fuel	Total Number of Unit Hours By Units With	Percent Unit Hours With Negative Markup And No Matching Fuel	Number of Unit Hours With Negative Markup And No Matching Fuel	Total Number of Unit Hours By Units With	Percent Unit Hours With Negative Markup And No Matching Fuel
	on Cost	Multiple Fuels	on Cost	on Cost	Multiple Fuels	on Cost
Jan	6,496	198,768	3.3%	6,496	191,950	3.4%
Feb	6,904	185,328	3.7%	6,904	172,135	4.0%
Mar	6,099	207,881	2.9%	6,099	168,266	3.6%
Apr	3,998	205,968	1.9%	3,998	167,623	2.4%
May	9,494	205,368	4.6%	9,494	184,625	5.1%
Jun	11,758	193,320	6.1%	11,758	182,862	6.4%
Jul	8,073	200,568	4.0%	8,073	195,537	4.1%
Aug	6,710	199,320	3.4%	6,710	192,313	3.5%
Sep	5,865	188,256	3.1%	5,865	173,195	3.4%
Oct	4,310	188,976	2.3%	4,310	150,515	2.9%
Nov	5,311	176,170	3.0%	5,311	138,928	3.8%
Dec	8,038	180,576	4.5%	8,038	165,460	4.9%
Total	83,056	2,330,499	3.6%	83,056	2,083,409	4.0%

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

Levels of offer capping have historically been low in PJM, as shown in Table 3-114. 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.¹⁶⁸ Units running in real time as part of their original commitment on the price-based offer on economics, and that can provide incremental relief to a constraint, cannot be switched to their cost-based offer.

The offer capping percentages shown in Table 3-113 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.¹⁶⁹ 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.

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.

¹⁶⁸ See OA Schedule 1 § 6.4.1.

¹⁶⁹ Prior to the 2018 Quarterly State of the Market Report for PJM: January through June, these tables presented the offer cap percentages based on total bid unit hours and total load MWh. Beginning with the quarterly report for January through June, 2018, the statistics have been updated with percentages based on run hours and total generation MWh from units modeled in the energy market.

Table 3-113 Offer capping statistics – energy only: 2017 to 2022

Year	Real-Time		Day-Ahead	
	Unit Hours		Unit Hours	
	Capped	MWh Capped	Capped	MWh Capped
2017	0.3%	0.2%	0.0%	0.0%
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	1.5%	1.2%	1.6%	1.0%
2022	1.3%	1.2%	1.7%	1.4%

Table 3-114 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 3-115. 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 3-113. 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 3-115.

Table 3-114 Offer capping statistics for energy and reliability: 2017 to 2022

Year	Real-Time		Day-Ahead	
	Unit Hours		Unit Hours	
	Capped	MWh Capped	Capped	MWh Capped
2017	0.4%	0.4%	0.1%	0.2%
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%

Table 3-115 shows the offer capping percentages only for units committed for reliability reasons, black start or reactive support. The low offer capping percentages do not mean that units manually committed for reliability reasons do not have market power. All units manually committed for reliability have market power and all are treated as if they had market power. These units are not capped to their cost-based offers because they tend to offer with a negative markup in their price-based offers, particularly at the economic minimum level, which

means that PJM's offer capping process results in the use of the price-based offer for commitment. However, the price-based offers have inflexible parameters such as longer minimum run times that may lead to higher total commitment cost if the unit was only needed for a shorter period that is less than its inflexible minimum run time.

Table 3-115 Offer capping statistics for reliability: 2017 to 2022

Year	Real-Time		Day-Ahead	
	Unit Hours		Unit Hours	
	Capped	MWh Capped	Capped	MWh Capped
2017	0.10%	0.20%	0.10%	0.20%
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%

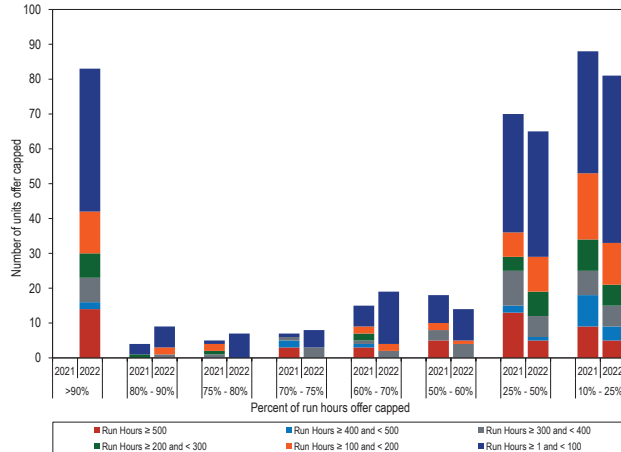
Table 3-116 presents data on the frequency with which units were offer capped in 2021 and 2022 as a result of failing the TPS test to provide energy for constraint relief in the real-time energy market, or for reliability reasons. Table 3-116 shows that 83 units were offer capped for 90 percent or more of their run hours in 2022, compared to zero units in 2021. Of these 83 units, 41 ran for less than 100 hours in 2022.

Table 3-116 Real-time offer capped unit statistics: 2021 and 2022

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Offer-Capped Hours						
	Year	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
		Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2021	0	0	0	0	0	0
	2022	14	2	7	7	12	41
80% and < 90%	2021	0	0	0	1	0	3
	2022	0	0	1	0	2	6
75% and < 80%	2021	0	0	1	1	2	1
	2022	0	0	0	0	0	7
70% and < 75%	2021	3	2	1	0	0	1
	2022	0	0	3	0	0	5
60% and < 70%	2021	3	1	1	2	2	6
	2022	0	0	2	0	2	15
50% and < 60%	2021	5	0	3	0	2	8
	2022	0	0	4	0	1	9
25% and < 50%	2021	13	2	10	4	7	34
	2022	5	1	6	7	10	36
10% and < 25%	2021	9	9	7	9	19	35
	2022	5	4	6	6	12	48

Figure 3-76 shows the frequency with which units were offer capped in 2021 and 2022 for failing the TPS test to provide energy for constraint relief in the real-time energy market or for reliability reasons.

Figure 3-76 Real-time offer capped unit statistics: 2021 and 2022



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

$(Price - Cost)/Price$.¹⁷⁰ The markup index is normalized and can vary from -1.00 when the offer price is less than the cost-based offer price, to 1.00 when the offer price is higher than the cost-based offer price. The markup index does not measure the impact of unit markup on total LMP. The dollar markup for a unit is the difference between price and cost.

Real-Time Markup Index

Table 3-117 shows the average markup index of marginal units in the real-time energy market, by offer price category using unadjusted cost-based offers. Table 3-119 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.

Table 3-118 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.¹⁷¹ 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

¹⁷⁰ 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.

¹⁷¹ 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.

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.¹⁷²

In 2022, the average dollar markups of units with offer prices less than \$10 was negative (-\$1.07 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between \$10 and \$15 was negative (-\$0.91 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 2022, 4.3 percent had offer prices above \$150 per MWh. Among the units that were marginal in 2021, 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 2022 was more than \$900, and the highest markup in 2021 was more than \$400.

172 See PJM, "Manual 15: Cost Development Guidelines," Rev. 39 (Jan. 18, 2022).

Table 3-117 Real-time average marginal unit markup index (By offer price category unadjusted): 2021 and 2022

Offer Price Category	2021			2022		
	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< \$10	0.23	(\$5.22)	7.1%	1.62	(\$1.07)	13.7%
\$10 to \$15	(0.07)	(\$1.37)	4.0%	0.05	(\$0.91)	1.0%
\$15 to \$20	(0.04)	(\$0.90)	17.3%	(0.12)	(\$3.68)	1.5%
\$20 to \$25	(0.03)	(\$0.86)	19.3%	(0.03)	(\$1.88)	2.7%
\$25 to \$50	0.01	(\$0.21)	40.9%	0.01	(\$0.32)	41.7%
\$50 to \$75	0.10	\$4.98	8.0%	0.03	\$1.33	21.3%
\$75 to \$100	0.23	\$19.14	1.2%	0.04	\$2.34	8.6%
\$100 to \$125	0.26	\$27.67	0.5%	0.10	\$9.43	3.7%
\$125 to \$150	0.33	\$44.44	0.2%	0.14	\$17.65	1.6%
>= \$150	0.11	\$24.94	1.5%	0.09	\$20.25	4.2%
All Offers	0.01	\$0.39	100.0%	0.16	\$1.58	100.0%

Table 3-119 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.¹⁷³

Table 3-118 Real-time average marginal unit markup index (By offer price category adjusted): 2021 and 2022

Offer Price Category	2021			2022		
	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< \$10	0.24	(\$5.16)	7.1%	1.63	(\$0.99)	13.7%
\$10 to \$15	(0.00)	(\$0.23)	4.0%	0.10	\$0.21	1.0%
\$15 to \$20	0.04	\$0.51	17.3%	(0.05)	(\$1.90)	1.5%
\$20 to \$25	0.05	\$0.99	19.3%	0.04	\$0.13	2.7%
\$25 to \$50	0.08	\$2.40	40.9%	0.08	\$2.63	41.7%
\$50 to \$75	0.17	\$9.30	8.0%	0.10	\$5.58	21.3%
\$75 to \$100	0.30	\$24.45	1.2%	0.11	\$8.38	8.6%
\$100 to \$125	0.32	\$34.30	0.5%	0.16	\$17.12	3.7%
\$125 to \$150	0.38	\$51.04	0.2%	0.19	\$26.02	1.6%
\$150 to \$400	0.19	\$38.68	1.5%	0.16	\$36.58	4.0%
>= \$400	0.61	\$265.77	0.0%	0.11	\$80.64	0.3%
All Offers	0.08	\$2.80	100.0%	0.22	\$5.56	100.0%

Table 3-120 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 2022, using unadjusted cost-based offers for coal units, 33.86 percent of marginal coal units had negative markups. The share of marginal gas units with negative markups at the dispatch point on their offer curve decreased from 46.55 percent in 2021 to 43.85 percent in 2022 when using unadjusted cost based offers.

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

Table 3-119 Percent of marginal units with markup below, above and equal to zero (By fuel type with unadjusted offers): 2021 and 2022

Type/Fuel	2021			2022		
	Negative	Zero	Positive	Negative	Zero	Positive
Coal	46.93%	23.20%	29.87%	33.86%	15.45%	50.70%
Gas	46.55%	17.03%	36.42%	43.85%	16.44%	39.71%
Oil	4.43%	93.93%	1.64%	2.13%	97.45%	0.42%

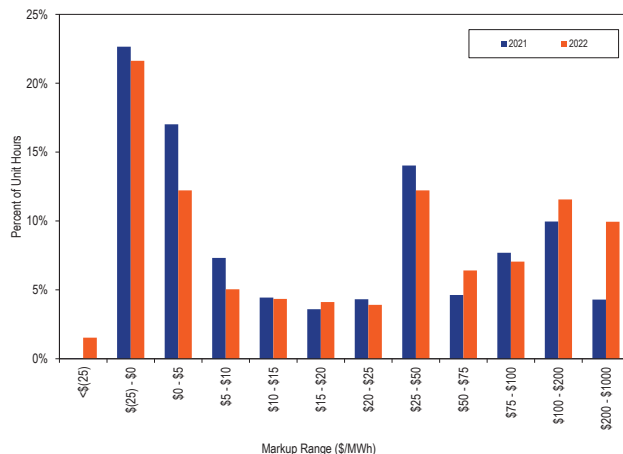
In 2022, using adjusted cost-based offers for coal units, 20.23 percent of marginal coal units had negative markups.

Table 3-120 Percent of marginal units with markup below, above and equal to zero (By fuel type with adjusted offers): 2021 and 2022

Type/Fuel	2021			2022		
	Negative	Zero	Positive	Negative	Zero	Positive
Coal	29.43%	13.46%	57.11%	20.23%	7.51%	72.26%
Gas	30.04%	8.40%	61.55%	29.75%	10.48%	59.77%
Oil	1.77%	93.28%	4.94%	2.10%	96.53%	1.37%

Figure 3-77 shows the frequency distribution of hourly markups for all gas units offered in 2021 and 2022 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.¹⁷⁴ Of the gas units offered in the PJM market in 2022, 23.1 percent of gas unit hours had a maximum markup that was negative and 21.5 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 2022 compared to 2021 and the share of marginal gas units with negative markups also decreased.

Figure 3-77 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: 2021 and 2022



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

Figure 3-78 shows the frequency distribution of hourly markups for all coal units offered in 2021 and 2022 using unadjusted cost-based offers. Of the coal units offered in the PJM market in 2022, 24.9 percent of coal unit hours had a maximum markup that was negative or equal to zero, increasing from 21.9 in 2021. The share of offered coal units with maximum markup that was negative increased in 2022 and the share of marginal coal units with negative markups decreased in 2022 compared to 2021.

Figure 3-78 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: 2021 and 2022

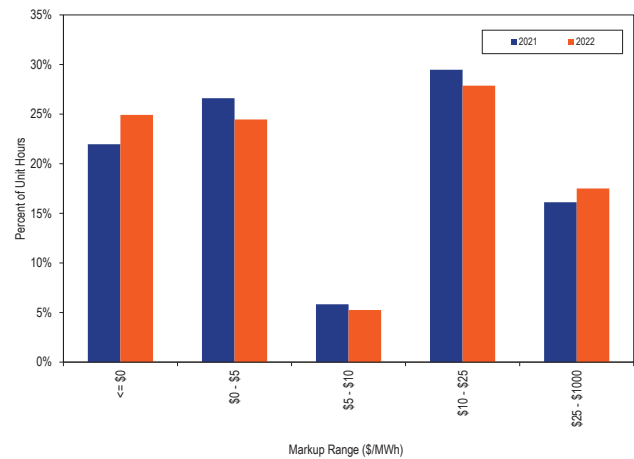
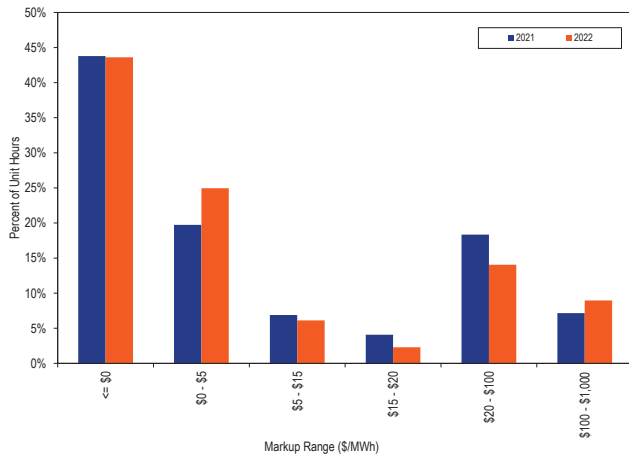


Figure 3-79 shows the frequency distribution of hourly markups for all offered oil units in 2021 and 2022 using unadjusted cost-based offers. Of the oil units offered in the PJM market in 2022, 43.6 percent of oil unit hours had a maximum markup that was negative or equal to zero. More than 8.9 percent of oil fired unit hours had a maximum markup above \$100 per MWh.

Figure 3-79 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: , 2021 and 2022

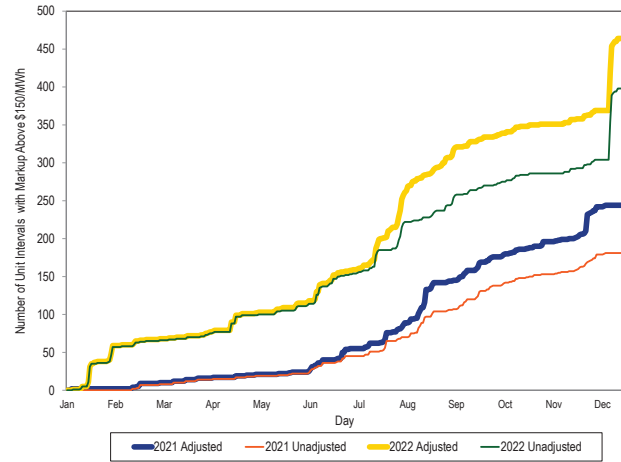


The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion 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 3-80 shows the number of marginal unit intervals in 2022 and 2021 with markup above \$150 per MWh. For 42.4 percent of the marginal unit intervals with markups above \$150 per MWh, the units failed the TPS test. These exercises of market power are a result of PJM’s failure to address the issues with the offer capping process identified by the MMU. If PJM adopted the MMU’s recommendations, these exercises of market power would not occur. During Elliott, a significant number of marginal units had markups above \$150 per MWh.

Figure 3-80 Cumulative number of unit intervals with markups above \$150 per MWh: 2021 and 2022



Day-Ahead Markup Index

Table 3-121 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using unadjusted cost-based offers. The majority of marginal units are virtual transactions, which do not have markup. The average dollar markups of units with offer prices less than \$10 was positive (\$9.02 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between \$10 and \$15 was positive (\$21.59 per MWh) when using unadjusted cost-based offers. In 2022, the average markup index and average dollar markups increased significantly in all price offer categories except offer prices between \$50 and \$125 compared to 2021 due to high markups of some units during the cold weather days in January and February of 2022.

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 2022 was more than \$300 per MWh while the highest markup in 2021 was more than \$100 per MWh.

Table 3-121 Average day-ahead marginal unit markup index (By offer price category, unadjusted): 2021 and 2022

Offer Price Category	2021			2022		
	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< \$10	0.26	\$0.58	1.5%	7.20	\$9.02	0.6%
\$10 to \$15	0.10	\$0.63	0.4%	2.06	\$21.59	0.2%
\$15 to \$20	0.09	\$1.26	2.8%	0.71	\$11.98	0.4%
\$20 to \$25	0.00	(\$0.30)	4.0%	0.36	\$6.74	0.4%
\$25 to \$50	0.04	\$0.73	8.7%	0.14	\$4.64	6.4%
\$50 to \$75	0.15	\$4.19	1.7%	0.10	\$5.87	4.4%
\$75 to \$100	0.30	\$24.62	0.2%	0.15	\$11.32	1.8%
\$100 to \$125	0.34	\$35.20	0.1%	0.26	\$28.04	0.7%
\$125 to \$150	0.15	\$20.14	0.0%	0.31	\$42.03	0.3%
>= \$150	0.02	\$3.18	0.2%	0.20	\$40.68	0.5%
All Offers	0.07	\$1.36	19.5%	0.46	\$9.22	15.6%

Table 3-122 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 2022, 0.4 percent of day-ahead marginal resources had offers between \$15 and \$20 per MWh, and the average dollar markup and the average markup index were both positive. The average markup index increased from 0.28 in 2021, to 7.21 in 2022 in the offer price category less than \$10.

Table 3-122 Average day-ahead marginal unit markup index (By offer price category, adjusted): 2021 and 2022

Offer Price Category	2021			2022		
	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< \$10	0.28	\$0.72	1.5%	7.21	\$8.75	0.6%
\$10 to \$15	0.18	\$1.82	0.4%	2.10	\$22.14	0.2%
\$15 to \$20	0.17	\$2.80	2.8%	0.78	\$13.05	0.4%
\$20 to \$25	0.09	\$1.78	4.0%	0.43	\$8.44	0.4%
\$25 to \$50	0.12	\$3.83	8.7%	0.21	\$7.85	6.4%
\$50 to \$75	0.22	\$9.12	1.7%	0.18	\$10.81	4.4%
\$75 to \$100	0.36	\$29.99	0.2%	0.22	\$18.09	1.8%
\$100 to \$125	0.40	\$42.14	0.1%	0.33	\$35.58	0.7%
\$125 to \$150	0.20	\$26.18	0.0%	0.37	\$50.48	0.3%
>= \$150	0.10	\$19.76	0.2%	0.27	\$60.66	0.5%
All Offers	0.15	\$4.07	19.5%	0.53	\$13.84	15.6%

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 3-123 shows the caps on the three parts of cost-based and price-based offers.

Table 3-123 Cost-based and price-based offer caps

No Load and Start			
Offer Type	Cost Option	Incremental Offer Curve Cap	No Load Cost Cap
Cost-Based	Cost-Based	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies	Start Cost Cap
			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
	Price-Based		No cap but can only be changed twice a year.

Table 3-124 shows the number of units that chose the cost-based option and the price-based option. In 2022, 89 percent of all generators that submitted no load or start costs chose to have cost-based no load and start costs in their price-based offers, two percentage points lower than in 2021.

Table 3-124 Number of units selecting cost-based and price-based no load and start costs: 2021 and 2022

No Load and Start Cost Option	2021		2022	
	Number of units	Percent	Number of units	Percent
Cost-Based	523	91%	511	89%
Price-Based	50	9%	62	11%
Total	573	100%	573	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 3-125 shows the average markup in the no load and start costs in the first nine months of 2021 and 2022. Generators that selected the cost-based start and no load option offered on average with a negative markup on the no load cost and a negative markup on the start costs. The price-based offers were lower than the cost-based offers. Generators that selected the price-based start and no load option offered on average with a negative markup on the no load cost but with very large positive markups on the start costs.

Table 3-125 No load and start cost markup: 2021 and 2022

Period	No Load and Start Cost Option	No Load Cost	Cold Start Cost	Intermediate Start Cost	Hot Start Cost
2021	Cost-Based	(7%)	(8%)	(9%)	(9%)
	Price-Based	(48%)	281%	309%	377%
2022	Cost-Based	(8%)	(8%)	(7%)	(7%)
	Price-Based	(52%)	111%	109%	129%

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 2022, 7.3 percent of the marginal units set prices based on cost-based offers, 0.2 percentage points higher than in 2021.

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 under PJM rules as of April 15, 2019: variable costs, avoidable costs, and fixed costs. The criterion for whether a generator may include a cost in an energy market cost-based offer, a variable cost, is that the cost is “directly related to electric production.”¹⁷⁵

Variable costs are comprised of short run marginal costs and avoidable costs that are directly related to electric production. Short run marginal costs are the cost of inputs consumed or converted to produce energy, and the costs associated with byproducts that result from consuming or converting materials to produce energy, net of any revenues from the sale of those byproducts. The categories of short run marginal costs are fuel costs, emission allowance costs, operating costs, and energy market opportunity costs.¹⁷⁶

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 3-126 shows the status of all fuel cost policies (FCP). As of December 31, 2022, 726 units (89 percent) had an FCP passed by the MMU and 94 units (11 percent) had an FCP failed by the MMU. The units with fuel cost policies failed by the MMU represented 20,839 MW. All units’ FCPs were approved by PJM. As of December 31, 2022, 489 units did not have FCPs. Units without FCPs cannot submit nonzero cost based offers, unless they use the temporary cost method.¹⁷⁷

Table 3-126 FCP Status for PJM generating units: December 31, 2022

PJM Status	MMU Status			Total
	Pass	Submitted	Fail	
Submitted	0	0	0	0
Under Review	0	0	0	0
Customer Input Required	0	0	0	0
Approved	726	0	94	820
Total	726	0	94	820

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.¹⁷⁸ Verifiable means that the FCP requires a market seller to provide a fuel price that can be

¹⁷⁵ See 167 FERC ¶ 61,030 (2019).

¹⁷⁶ See OA Schedule 2 § 1.1(a).

¹⁷⁷ See OA Schedule 2 § 2.1.

¹⁷⁸ 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”).

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.¹⁷⁹ 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.¹⁸⁰ 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').¹⁸¹

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).¹⁸²

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 unverifiable fuel costs and the use of available market information that results in inaccurate expected costs.

Some of the failed fuel cost policies include unverifiable cost estimates. Some policies include options under which the estimate of the natural gas commodity cost can be calculated by the market seller without specifying a verifiable, systematic method. For example, some FCPs specify that the source of the natural gas cost would be communications with traders within the market seller's organization. A fuel cost from discretionary and undocumented decision making within the market seller's organization is not verifiable. The point of FCPs is to eliminate such practices as the basis for fuel costs, as most companies have done. Verifiability requires that fuel cost estimates be transparently derived from market information and that PJM or the MMU could reproduce the same fuel cost estimates after the fact by applying the methods documented in the FCP to the same inputs. Verifiable is a key requirement of an FCP. If it is not verifiable, an FCP is meaningless and has no value. Unverifiable fuel costs permit the exercise of market power.

Some of the failed fuel cost policies 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.

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 15.¹⁸³

¹⁷⁹ Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) at P 8 ("September 16th Filing").

¹⁸⁰ October 7th Filing at P12; 158 FERC ¶ 61,133 at P 57 (2017).

¹⁸¹ September 16th Filing at P 8.

¹⁸² See PJM Operating Agreement Schedule 2 § 2.3 (a).

¹⁸³ See OA Schedule 2 § 6.

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

In 2022, 116 penalty cases were identified, 94 resulted in assessed cost-based offer penalties and 22 remain pending PJM's determination. These cases were for 110 units owned by 20 different companies. Table 3-128 shows the penalties by the year in which participants were notified.

Table 3-127 Cost-based offer penalty cases by year notified: May 2017 through December 2022

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	94	50	0	22	110	20
Total	688	629	116	37	22	451	66

Since 2017, 688 penalty cases have been identified, 629 resulted in assessed cost-based offer penalties, 37 resulted in disagreement between the MMU and PJM, 22 remain pending PJM's determination and 116 were self identified by market sellers. The 629 cases were from 451 units owned by 66 different companies. The total penalties were \$4.0 million, charged to units that totaled 125,062 available MW. The average penalty was \$1.45 per available MW. This means that a 100 MW unit would have paid a penalty of \$3,488.¹⁸⁴ In some cases where the penalized unit operates, the increase to LMP and/or uplift due to the incorrect offer exceeds the amount of the penalty. Table 3-128 shows the total cost-based offer penalties since 2017 by year.

Table 3-128 Cost-based offer penalties by year: May 2017 through December 2022

Year	Number of units	Number of companies	Penalties	Average Available Capacity Charged (MW)	Average Penalty (\$/MW)
2017	92	20	\$556,826	16,930	\$1.56
2018	127	33	\$1,242,102	25,743	\$2.28
2019	73	22	\$378,245	15,073	\$1.14
2020	140	26	\$407,283	21,908	\$0.85
2021	125	24	\$753,463	24,808	\$1.31
2022	96	18	\$707,005	20,600	\$1.43
Total	653	64	\$4,044,924	125,062	\$1.45

The incorrect cost-based offers resulted from incorrect application of fuel cost policies, lack of approved fuel

cost policies, fuel cost policy violations, miscalculation of no load costs, inclusion of prohibited maintenance costs, use of incorrect incremental heat rates, use of incorrect start cost, and use of incorrect emission costs.

2020 Fuel Cost Policy Changes

On July 28, 2020, the Commission approved tariff revisions that modified the fuel cost policy process and the cost-based offer penalties.¹⁸⁵

The tariff revisions replaced the annual review process with a periodic review set by PJM. The revisions reinstated the periodic review process employed by the MMU prior to PJM's involvement in the review and approval of fuel cost policies. Monitoring participant behavior through the use of fuel cost policies is an ongoing process that necessitates frequent updates.

Market sellers must revise their fuel cost policies whenever circumstances change that impact fuel pricing (e.g. different pricing points, dual fuel addition capability).

The tariff revisions removed the requirement for units with zero marginal cost to have an approved fuel cost policy but also included a zero offer cap for cost-based offers for units that do not have an approved fuel cost policy.

The tariff revisions allow a temporary cost offer method for units that do not have an approved fuel cost policy. The revisions allow units to submit nonzero cost-based offers without an approved fuel cost policy if they follow the temporary cost offer method. The use of the method results in cost-based offers that do not follow the fuel cost policy rules. The approach significantly weakens market power mitigation by allowing market sellers to make offers without an approved fuel cost policy. The proposed approach allows the use of an inaccurate and unsupported fuel cost calculation in place of an accurate fuel cost policy.

The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy.

¹⁸⁴ 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.

¹⁸⁵ 172 FERC ¶ 61,094 (2020).

The tariff revisions replace the fuel cost policy revocation provision with the ability for PJM to terminate fuel cost policies.

The tariff revisions reduce the penalties for noncompliant cost-based offers in two situations. When market sellers report their noncompliant cost-based offers, the penalty is reduced by 75 percent. When market sellers do not meet conditions defined to measure a potential market impact the penalty is reduced by 90 percent. The conditions include if the market seller failed the TPS test, if the unit was committed on its cost-based offer, if the unit was marginal or if the unit was paid uplift.

The tariff revisions eliminate penalties entirely when units submit noncompliant cost-based offers if PJM determines that an unforeseen event hindered the market seller's ability to submit a compliant cost-based offer. This new provision allows market sellers to not follow their fuel cost policy, submit cost-based offers that are not verifiable or systematic and not face any penalties for doing so.

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

Cost Development Guidelines

The Cost Development Guidelines contained in PJM Manual 15 do not clearly or accurately describe the short run marginal cost of generation. The MMU recommends that PJM Manual 15 be replaced or updated with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers. In 2022, PJM made updates recommended by the MMU to Manual 15 to add straightforward descriptions for some of the most essential cost offer calculations.¹⁸⁶

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.¹⁸⁷ The changes proposed by PJM attempted but failed to clarify the rules. The proposed rules defined all costs directly related to

electricity production as includable in cost-based offers. This also included the long term maintenance costs of combined cycles and combustion turbines, which had been explicitly excluded in PJM Manual 15.

On April 15, 2019, FERC accepted PJM's filing order, subject to revisions requested by FERC.¹⁸⁸ On October 28, 2019, FERC issued a final order accepting PJM's compliance filing.¹⁸⁹ 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.

PJM allows for the calculation of VOM costs in dollars per MWh, dollars per MMBtu, dollars per run hour, dollars per equivalent operating hour (EOH) and dollars per start. The MMU converted all VOM costs into dollars per MWh using the units' heat rates, the average economic maximum and average minimum run time of the units in 2022.

The average variable operating and maintenance cost approved by PJM for combustion turbines and diesels for 2022 was five percent higher than the approved variable operating and maintenance cost approved by PJM in 2021.¹⁹⁰

¹⁸⁶ See PJM Manual 15: Cost Development Guidelines, Revision 42 (Oct. 28, 2022).

¹⁸⁷ See PJM Interconnection Maintenance Adder Revisions to the Amended and Restated Operating Agreement, LLC, Docket No. EL19-8-000.

¹⁸⁸ 167 FERC ¶ 61,030 (2019).

¹⁸⁹ 168 FERC ¶ 61,134 (2019).

¹⁹⁰ PJM reviews VOM once per year. The results reflect PJM's most recent review.

The average variable operating and maintenance cost approved by PJM for combined cycles for 2022 was two percent lower than the approved variable operating and maintenance cost approved by PJM in 2021.

The average variable operating and maintenance cost approved by PJM for coal units for 2022 was one percent lower than the approved variable operating and maintenance cost approved by PJM in 2021.

Table 3-129 shows the amount of capacity offered by range of VOM costs. Table 3-129 shows that 1,135 MW have an approved effective VOM above \$100 per MWh and 1,736 MW have an approved effective VOM between \$50 and \$100 per MWh.

Table 3-129 Approved effective VOM costs in dollars per MWh: 2019 through 2022

Approved VOM Range (\$/MWh)	Offered MW			
	2019	2020	2021	2022
\$0 to \$5 per MWh	69,025	71,898	64,131	65,533
\$5 to \$10 per MWh	37,325	30,325	34,369	38,588
\$10 to \$20 per MWh	14,276	15,931	21,492	17,010
\$20 to \$50 per MWh	5,402	4,938	5,015	7,366
\$50 to \$100 per MWh	2,302	3,146	2,324	1,736
Above \$100 per MWh	1,159	1,044	772	1,135

The level of costs accepted by PJM for inclusion in VOM depends on PJM's interpretation of the maintenance activities or expenses directly related to electricity production and the level of detailed support provided by market sellers to PJM.

PJM's VOM review is not adequate to determine whether all costs included in VOM are compliant. PJM's VOM review focuses only on the expenses submitted for the last year of up to 20 years of data. For example, a market seller can provide data from 2010 without any supporting documentation as long as the data from 2021 (last year) has documentation. PJM's review is dependent on the level of detail provided by the market seller. Recent changes in PJM's review process, triggered by MMU questions, required more details from market sellers and have led to the appropriate exclusion of expenses that were previously included.¹⁹¹

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.

The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics.

The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced.

The MMU understands that companies have different document retention policies but in order to be allowed to include maintenance costs, such costs must be verified, and they cannot be verified without documentation. Supporting documentation includes internal financial records, maintenance project documents, invoices, and contracts. Market participants should be required to provide the operational data (e.g. run hours, MWh, MMBtu) that supports the maintenance cycle of the equipment being serviced/replaced. For example, if equipment is serviced every 5,000 run hours, the market participant must include at least 5,000 run hours of historical operation in its maintenance cost history.

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

¹⁹¹ 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>>.

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.¹⁹²

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 with an effective date of June 1, 2023.¹⁹³

Combined Cycle Start Heat Input Definition

PJM Manual 15 defines the start heat input of combined cycles as the amount of fuel used from the firing of the first combustion turbine to the close of the steam turbine breaker plus any fuel used by other combustion turbines in the combined cycle from firing to the point at which the HRSG steam pressure matches the steam turbine steam pressure. This definition is inappropriate given that after each combustion turbine is synchronized, some of the fuel is used to produce energy for which the unit is compensated in the energy market. To account

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

The MMU recommended changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. This change will make the treatment of combined cycles consistent with steam turbines. Exceptions to this definition should be granted when the amount of fuel used from synchronization to steam turbine breaker close is greater than the no load heat plus the output during this period times the incremental heat rate.

In 2022, the MMU and PJM proposed changing the start cost definition of units with a steam process to include the costs from the beginning of the start sequence to dispatchable.¹⁹⁴ The new definition included what is commonly considered 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 MWh produced before the unit becomes dispatchable. The proposal was approved by the Commission on January 10, 2023, with an effective date of June 1, 2023.¹⁹⁵

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

¹⁹² The peak adder is equal to \$300 times three divided by 5 MW.

¹⁹³ See Federal Energy Regulatory Commission, Docket No. ER23-557-000 (January 10, 2023) at 1.

¹⁹⁴ See "Start Cost Alternate Proposal," MMU presentation to the Cost Development Subcommittee. (December 2, 2021) <[20211202-item-06-start-cost-alternate-proposal.lashx](#)>.

¹⁹⁵ See Federal Energy Regulatory Commission, Docket No. ER23-557-000 (January 10, 2023) at 1.

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

Nuclear Costs

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

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

Pumped Hydro Costs

The calculation of pumped hydro costs for energy storage in Section 7.3 of PJM Manual 15 is inaccurate. The mathematical formulation does not take into account the purchase of power for pumping in the day-ahead market.

The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases.

Gas Pipeline Penalties

Section 2.2.2 of PJM Manual 15 states that gas pipeline penalties are not includable in cost-based offers. Penalties can be incurred by units for many situations, for example, withdrawing gas not nominated and deviating from an imposed threshold during an operational flow order. Any unit with cost-based offers that include gas pipeline penalties will be subject to penalties per Schedule 2 of the PJM Operating Agreement.

Many Market Sellers rely on independent third party quotes to estimate or determine the gas spot price. The quotes received from these third parties should not be based on incurring gas pipeline penalties. It is recommended that Market Sellers confirm with their third parties that gas is available to them without the need to incur gas pipeline penalties. If that is not

possible, the units should be unavailable until the third party can confirm that gas is available without incurring penalties.

Frequently Mitigated Units (FMU) and Associated Units (AU)

The rules for determining the qualification of a unit as an FMU or AU became effective November 1, 2014. The number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero units eligible for an FMU or AU adder for the period between December 2014 and August 2019.¹⁹⁶ One unit qualified for an FMU adder for the months of September and October, 2019. In 2020, five units qualified for an FMU adder in at least one month. In 2021, one unit qualified for an FMU adder in January. In 2022, no units qualified for an FMU adder.

Table 3-130 shows, by month, the number of FMUs and AUs from January 2021 through December 2022. 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 3-130 Number of frequently mitigated units and associated units (By month): January 2021 through December 2022

	2021				2022			
	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
February	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0
June	0	0	0	0	0	0	0	0
July	0	0	0	0	0	0	0	0
August	0	0	0	0	0	0	0	0
September	0	0	0	0	0	0	0	0
October	0	0	0	0	0	0	0	0
November	0	0	0	0	0	0	0	0
December	0	0	0	0	0	0	0	0

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 \$/MWh-year) were greater than zero, and if the generating unit

¹⁹⁶ For a definition of FMUs and AUs, and for historical FMU/AU results, see the 2018 *State of the Market Report for PJM*, Volume II, Section 3, Energy Market, at Frequently Mitigated Units (FMU) and Associated Units (AU).

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 3-131 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.¹⁹⁷ The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of 2022, and summed by the parent company that offers the marginal resource into the real-time energy market. In 2022, the offers of one company resulted in 14.8 percent of the real-time load-weighted PJM system LMP and the offers of the top four companies resulted in 48.3 percent of the real-time load-weighted average PJM system LMP. In 2022, the offers of one company resulted in 15.4 percent of the peak hour real-time load-weighted PJM system LMP.

Table 3-131 Marginal unit contribution to real-time load-weighted LMP (By parent company): 2021 and 2022

2021						2022					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	12.9%	12.9%	1	16.2%	16.2%	1	14.8%	14.8%	1	15.4%	15.4%
2	12.0%	25.0%	2	10.8%	26.9%	2	11.6%	26.4%	2	13.2%	28.6%
3	10.3%	35.3%	3	10.3%	37.2%	3	8.6%	35.0%	3	8.3%	36.9%
4	5.9%	41.2%	4	5.5%	42.8%	4	8.2%	43.2%	4	7.9%	44.8%
5	5.4%	46.6%	5	5.4%	48.2%	5	5.1%	48.3%	5	5.5%	50.3%
6	3.9%	50.6%	6	5.1%	53.3%	6	4.7%	53.0%	6	5.2%	55.4%
7	3.8%	54.4%	7	3.7%	56.9%	7	3.8%	56.8%	7	4.0%	59.5%
8	3.5%	57.9%	8	3.3%	60.2%	8	3.7%	60.5%	8	3.2%	62.7%
9	3.0%	60.9%	9	3.2%	63.4%	9	3.3%	63.8%	9	3.2%	65.9%
Other (76 companies)	39.1%	100.0%	Other (76 companies)	36.6%	100.0%	Other (97 companies)	36.2%	100.0%	Other (91 companies)	34.1%	100.0%

Figure 3-81 shows the marginal unit contribution to the real-time load-weighted PJM system LMP summed by parent companies for every year since 2012.

Figure 3-81 Marginal unit contribution to real-time load-weighted LMP (By parent company): 2012 through 2022

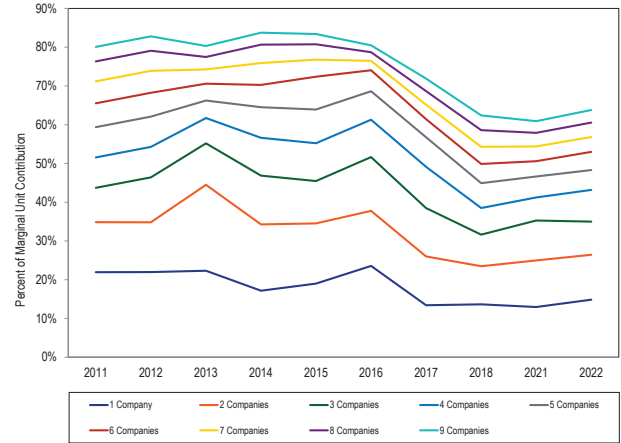


Table 3-132 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.¹⁹⁸ The contribution of each marginal resource to price at each load bus is calculated hourly, and summed by the parent company that offers the marginal resource into the day-ahead energy market. The results show that in 2022, the offers of one company contributed 13.1 percent of the day-ahead load-weighted average PJM system LMP and that the offers of the top four companies contributed 40.0 percent of the day-ahead load-weighted average PJM system LMP.

¹⁹⁷ See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

¹⁹⁸ Id.

Table 3-132 Marginal resource contribution to day-ahead load-weighted LMP (By parent company): 2021 and 2022

Company	2021					2022					
	All Hours		Peak Hours			All Hours		Peak Hours			
	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	6.4%	6.4%	1	7.7%	7.7%	1	13.1%	13.1%	1	23.1%	23.1%
2	5.2%	11.6%	2	6.4%	14.1%	2	10.5%	23.6%	2	12.4%	35.5%
3	5.1%	16.7%	3	5.0%	19.1%	3	8.2%	31.8%	3	9.6%	45.1%
4	4.5%	21.1%	4	4.6%	23.7%	4	8.1%	40.0%	4	9.5%	54.6%
5	4.4%	25.5%	5	4.4%	28.2%	5	7.7%	47.7%	5	9.5%	64.1%
6	3.9%	29.3%	6	3.8%	32.0%	6	7.3%	55.0%	6	7.8%	71.9%
7	3.6%	33.0%	7	3.1%	35.1%	7	6.4%	61.3%	7	5.5%	77.4%
8	3.5%	36.5%	8	3.0%	38.1%	8	6.2%	67.5%	8	5.2%	82.6%
9	3.0%	39.5%	9	3.0%	41.1%	9	5.4%	72.9%	9	4.9%	87.5%
Other (149 companies)	60.5%	100.0%	Other (145 companies)	58.9%	100.0%	Other (158 companies)	27.1%	100.0%	Other (148 companies)	12.5%	100.0%

Markup

The markup index is a measure of the competitiveness of participant behavior for individual units. The markup in dollars is a measure of the impact of participant behavior on the generator bus market price when a unit is marginal. As an example, if unit A has a \$90 cost and a \$100 price, while unit B has a \$9 cost and a \$10 price, both would show a markup index of 10 percent, but the price impact of unit A's markup at the generator bus would be \$10 while the price impact of unit B's markup at the generator bus would be \$1. Depending on each unit's location on the transmission system, those bus level impacts could also have different impacts on total system price. Markup can also affect prices when units with markups are not marginal by altering the economic dispatch order of supply.

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

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.

or cost-based, and the system price, based on the cost-based offers of those marginal units.

PJM implemented fast start pricing on September 1, 2021. Under the fast start pricing rules, the LMPs are calculated in the pricing run, where the offer price of a marginal fast start unit includes amortized commitment costs. For all the fast start marginal units starting from September 1, 2021, the markup includes markup in the incremental offer, markup in the amortized start up offer and markup in the amortized no load offer.

Table 3-133 shows the impact (markup component of LMP) of the marginal unit markup behavior by fuel type and unit type on the real-time load-weighted average system LMP using unadjusted and adjusted offers. The adjusted markup component of LMP increased from \$4.23 per MWh in 2021 to \$8.02 per MWh in 2022. The adjusted markup contribution of coal units in 2022 was \$2.38 per MWh. The adjusted markup component of gas fired units in 2022 was \$5.60 per MWh, an increase of \$2.51 per MWh from 2021. The markup component of wind units was less than \$0.0 per MWh. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In 2022, among the wind units that were marginal, 62.4 percent had negative offer prices.

Table 3-133 Markup component of real-time load-weighted average LMP by primary fuel type and unit type: 2021 and 2022²⁰⁰

Fuel	Technology	2021		2022	
		Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	\$0.71	\$1.19	\$1.70	\$2.38
Gas	CC	\$0.77	\$2.12	\$1.71	\$4.00
Gas	CT	\$0.32	\$0.93	\$0.07	\$1.45
Gas	RICE	(\$0.00)	\$0.01	(\$0.02)	\$0.05
Gas	Steam	(\$0.04)	\$0.03	(\$0.03)	\$0.10
Landfill Gas	CT	(\$0.00)	(\$0.00)	\$0.00	\$0.00
Municipal Waste	RICE	\$0.00	\$0.00	(\$0.00)	(\$0.00)
Oil	CC	\$0.00	\$0.00	(\$0.02)	(\$0.01)
Oil	CT	(\$0.00)	\$0.01	(\$0.06)	\$0.06
Oil	RICE	\$0.00	\$0.00	\$0.00	\$0.00
Oil	Steam	(\$0.07)	(\$0.06)	(\$0.06)	(\$0.05)
Other	Solar	\$0.00	\$0.00	\$0.01	\$0.01
Other	Steam	\$0.00	\$0.00	\$0.00	\$0.01
Wind		(\$0.02)	(\$0.02)	\$0.02	\$0.02
Total		\$1.69	\$4.23	\$3.32	\$8.02

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

Markup Component of Real-Time Price

Table 3-134 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-135 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on peak and off peak prices. In 2022, when using unadjusted cost-based offers, \$3.32 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-based offers, \$8.02 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In 2022, the peak markup component was highest in June, \$10.12 per MWh using unadjusted cost-based offers and peak markup component was highest in June, \$16.57 per MWh using adjusted cost-based offers. This corresponds to 8.0 percent and 13.1 percent of the real-time, peak, load-weighted, average LMP in June.

Table 3-134 Monthly markup components of real-time load-weighted LMP (Unadjusted): January 2021 through December 2022

	2021			2022		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	(\$0.46)	(\$0.30)	(\$0.60)	\$2.05	\$0.96	\$3.04
Feb	(\$0.53)	\$0.06	(\$1.12)	\$2.32	\$2.19	\$2.46
Mar	\$0.02	\$0.16	(\$0.13)	\$0.88	\$0.43	\$1.37
Apr	(\$1.69)	(\$2.56)	(\$0.72)	\$4.03	\$5.64	\$2.42
May	(\$0.02)	\$0.62	(\$0.62)	\$1.93	\$3.49	\$0.43
Jun	\$1.75	\$2.76	\$0.58	\$5.83	\$10.12	\$0.47
Jul	\$2.61	\$3.37	\$1.80	\$5.65	\$8.38	\$3.05
Aug	\$4.83	\$6.68	\$2.71	\$5.62	\$5.33	\$5.97
Sep	\$3.30	\$4.19	\$2.34	\$2.09	\$1.63	\$2.57
Oct	\$4.43	\$5.52	\$3.35	\$3.89	\$4.52	\$3.28
Nov	\$3.15	\$4.12	\$2.20	\$0.95	\$2.16	(\$0.25)
Dec	\$1.89	\$2.46	\$1.26	\$3.64	\$5.93	\$1.61
Total	\$1.69	\$2.41	\$0.94	\$3.32	\$4.37	\$2.26

Table 3-135 Monthly markup components of real-time load-weighted LMP (Adjusted): January 2021 through December 2022

	2021			2022		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	\$1.47	\$1.73	\$1.24	\$6.10	\$5.08	\$7.03
Feb	\$2.41	\$3.21	\$1.60	\$5.59	\$5.44	\$5.74
Mar	\$1.63	\$1.85	\$1.39	\$4.03	\$3.79	\$4.29
Apr	(\$0.08)	(\$0.97)	\$0.91	\$8.26	\$10.30	\$6.23
May	\$1.93	\$2.75	\$1.17	\$6.60	\$8.71	\$4.57
Jun	\$3.96	\$5.22	\$2.52	\$11.35	\$16.57	\$4.81
Jul	\$5.11	\$6.20	\$3.95	\$11.65	\$15.45	\$8.03
Aug	\$7.75	\$9.92	\$5.27	\$12.48	\$13.13	\$11.68
Sep	\$6.52	\$7.71	\$5.23	\$7.61	\$7.86	\$7.35
Oct	\$8.34	\$9.96	\$6.73	\$7.60	\$8.80	\$6.44
Nov	\$6.43	\$7.73	\$5.16	\$4.36	\$5.77	\$2.97
Dec	\$4.28	\$4.92	\$3.57	\$8.69	\$10.34	\$7.21
Total	\$4.23	\$5.18	\$3.24	\$8.02	\$9.54	\$6.48

Hourly Markup Component of Real-Time Prices

Figure 3-82 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in 2021 and 2022. Figure 3-83 shows the markup contribution to the hourly load-weighted LMP using adjusted cost-based offers in 2021 and 2022.

Figure 3-82 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): 2021 and 2022

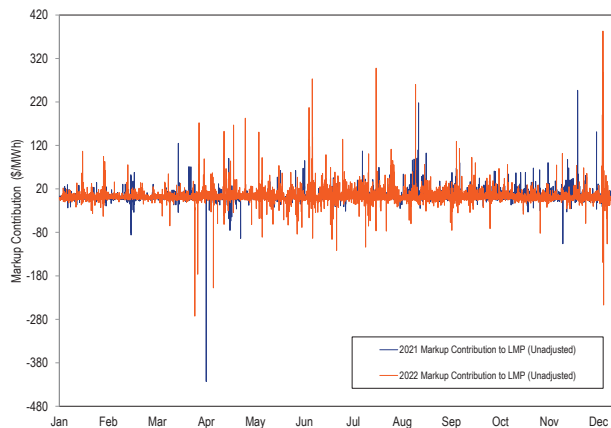
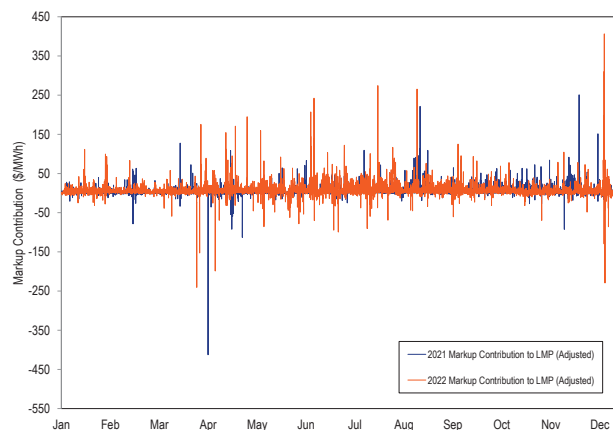


Figure 3-83 Markup contribution to real-time hourly load-weighted LMP (Adjusted): 2021 and 2022



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 2021 and 2022 in Table 3-136 and for adjusted offers in Table 3-137.²⁰¹ The smallest zonal all hours average markup component using unadjusted offers in 2022, was in the DPL Zone, \$1.76 per MWh, while the highest was in the BGE Zone, \$5.01 per MWh. The smallest zonal on peak average markup component using unadjusted offers in 2022, was in the DPL Zone, \$2.43 per MWh, while the highest was in the BGE Zone, \$6.02 per MWh.

Table 3-136 Real-time average zonal markup component (Unadjusted): 2021 and 2022

	2021			2022		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	\$0.95	\$1.59	\$0.28	\$1.96	\$2.62	\$1.29
AEP	\$1.86	\$2.64	\$1.06	\$3.40	\$4.72	\$2.06
APS	\$1.89	\$2.69	\$1.08	\$3.36	\$4.37	\$2.33
ATSI	\$1.87	\$2.62	\$1.10	\$3.25	\$4.60	\$1.87
BGE	\$2.27	\$3.07	\$1.45	\$5.01	\$6.02	\$3.99
COMED	\$1.75	\$2.55	\$0.92	\$2.98	\$4.23	\$1.71
DAY	\$1.96	\$2.72	\$1.18	\$3.40	\$4.77	\$2.02
DOM	\$1.99	\$2.82	\$1.14	\$4.46	\$5.34	\$3.57
DPL	\$1.16	\$1.89	\$0.42	\$1.76	\$2.43	\$1.08
DUKE	\$1.85	\$2.57	\$1.12	\$3.36	\$4.68	\$2.03
DUQ	\$1.81	\$2.52	\$1.09	\$3.15	\$4.45	\$1.83
EKPC	\$1.84	\$2.56	\$1.10	\$3.41	\$4.75	\$2.06
JCPLC	\$1.09	\$1.72	\$0.45	\$2.10	\$2.82	\$1.36
MEC	\$1.77	\$2.84	\$0.68	\$3.15	\$3.87	\$2.42
OVEC	\$1.84	\$2.42	\$1.24	\$3.17	\$4.20	\$2.12
PE	\$1.68	\$2.52	\$0.82	\$2.63	\$3.69	\$1.55
PECO	\$0.98	\$1.66	\$0.30	\$1.92	\$2.66	\$1.16
PEPCO	\$2.28	\$3.00	\$1.55	\$4.62	\$5.39	\$3.83
PPL	\$1.40	\$2.19	\$0.60	\$2.53	\$3.19	\$1.86
PSEG	\$1.15	\$1.79	\$0.50	\$2.31	\$3.16	\$1.45
REC	\$1.45	\$2.21	\$0.67	\$2.26	\$3.27	\$1.25

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.

Table 3-137 Real-time average zonal markup component (Adjusted): 2021 and 2022

	2021			2022		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	\$3.16	\$3.94	\$2.37	\$5.73	\$6.58	\$4.87
AEP	\$4.54	\$5.57	\$3.47	\$8.20	\$10.06	\$6.32
APS	\$4.60	\$5.66	\$3.51	\$8.25	\$9.77	\$6.72
ATSI	\$4.54	\$5.53	\$3.52	\$7.89	\$9.69	\$6.05
BGE	\$5.28	\$6.43	\$4.10	\$10.90	\$12.67	\$9.12
COMED	\$4.30	\$5.37	\$3.20	\$7.40	\$9.27	\$5.50
DAY	\$4.76	\$5.80	\$3.69	\$8.33	\$10.25	\$6.38
DOM	\$4.84	\$5.96	\$3.69	\$9.99	\$11.52	\$8.45
DPL	\$3.44	\$4.28	\$2.58	\$5.63	\$6.44	\$4.80
DUKE	\$4.54	\$5.53	\$3.53	\$8.15	\$10.00	\$6.27
DUQ	\$4.43	\$5.37	\$3.46	\$7.73	\$9.50	\$5.95
EKPC	\$4.52	\$5.50	\$3.51	\$8.22	\$10.08	\$6.33
JCPLC	\$3.39	\$4.17	\$2.59	\$5.95	\$6.81	\$5.06
MEC	\$4.37	\$5.75	\$2.94	\$7.68	\$8.77	\$6.57
OVEC	\$4.47	\$5.30	\$3.61	\$7.88	\$9.44	\$6.30
PE	\$4.23	\$5.31	\$3.13	\$6.98	\$8.38	\$5.55
PECO	\$3.18	\$3.97	\$2.36	\$5.54	\$6.41	\$4.66
PEPCO	\$5.19	\$6.21	\$4.15	\$10.25	\$11.73	\$8.76
PPL	\$3.81	\$4.84	\$2.76	\$6.68	\$7.57	\$5.77
PSEG	\$3.49	\$4.32	\$2.64	\$6.17	\$7.19	\$5.14
REC	\$3.90	\$4.93	\$2.85	\$6.23	\$7.43	\$5.00

Markup by Real-Time Price Levels

Table 3-138 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 3-138 Real-time markup contribution (By load-weighted LMP category, unadjusted): 2021 and 2022

LMP Category	2021		2022	
	Markup Component	Frequency	Markup Component	Frequency
< \$10	(\$10.48)	0.0%	(\$5.33)	0.1%
\$10 to \$15	(\$1.56)	0.5%	(\$2.15)	0.2%
\$15 to \$20	(\$0.94)	12.0%	(\$2.33)	0.3%
\$20 to \$25	(\$0.92)	20.1%	(\$2.04)	0.9%
\$25 to \$50	\$0.24	47.5%	(\$0.16)	35.6%
\$50 to \$75	\$4.70	13.8%	\$1.45	33.3%
\$75 to \$100	\$12.59	3.4%	\$4.01	14.8%
\$100 to \$125	\$16.47	1.5%	\$6.94	7.0%
\$125 to \$150	\$25.32	0.5%	\$10.65	3.5%
>= \$150	\$29.36	0.7%	\$22.31	4.3%

Table 3-139 Real-time markup contribution (By load-weighted LMP category, adjusted): 2021 and 2022

LMP Category	2021		2022	
	Markup Component	Frequency	Markup Component	Frequency
< \$10	(\$9.88)	0.0%	(\$4.21)	0.1%
\$10 to \$15	(\$0.35)	0.5%	(\$0.79)	0.2%
\$15 to \$20	\$0.52	12.0%	(\$0.71)	0.3%
\$20 to \$25	\$0.92	20.1%	(\$0.07)	0.9%
\$25 to \$50	\$2.70	47.5%	\$2.96	35.6%
\$50 to \$75	\$8.40	13.8%	\$5.73	33.3%
\$75 to \$100	\$16.71	3.4%	\$9.62	14.8%
\$100 to \$125	\$20.77	1.5%	\$14.00	7.0%
\$125 to \$150	\$29.93	0.5%	\$18.58	3.5%
>= \$150	\$33.29	0.7%	\$30.46	4.3%

Markup by Company

Table 3-140 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 2022, when using unadjusted cost-based offers, the markup of one company accounted for 1.4 percent of the load-weighted average LMP, the markup of the top five companies accounted for 3.6 percent of the load-weighted average LMP and the markup of all companies accounted for 4.1 percent of the load-weighted average LMP. The share of top five companies' markup contribution to the load-weighted average LMP decreased and the dollar values of their markup increased in 2022. The markup contribution to the load-weighted average LMP increased and share of the markup contribution to the load-weighted average LMP decreased in 2022. The markup contribution of a unit to the real-time load-weighted average LMP can be positive or negative.

Table 3-140 Markup component of real-time load-weighted average LMP by Company: 2021 and 2022

	2021				2022			
	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	\$0.55	1.4%	\$0.79	2.0%	\$1.13	1.4%	\$1.61	2.0%
Top 2 Companies	\$0.99	2.5%	\$1.55	3.9%	\$1.78	2.2%	\$2.51	3.1%
Top 3 Companies	\$1.31	3.3%	\$2.00	5.0%	\$2.33	2.9%	\$3.35	4.2%
Top 4 Companies	\$1.50	3.8%	\$2.30	5.8%	\$2.63	3.3%	\$3.93	4.9%
Top 5 Companies	\$1.66	4.2%	\$2.56	6.4%	\$2.92	3.6%	\$4.45	5.6%
All Companies	\$1.69	4.2%	\$4.23	10.6%	\$3.32	4.1%	\$8.02	10.0%

Day-Ahead Markup

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

The markup component of the PJM day-ahead load-weighted average LMP by primary fuel and unit type is shown in Table 3-141. INC, DEC and up to congestion transactions (UTC) have zero markups. UTCs were 49.0 percent of marginal resources, INCs were 16.3 percent of marginal resources and DECs were 18.8 percent of marginal resources in 2022.

The adjusted markup of coal, gas and oil units is calculated as the difference between the price-based offer and the cost-based offer excluding the 10 percent adder. Table 3-141 shows the markup component of LMP for marginal generating resources. Generating resources were only 15.6 percent of marginal resources in 2022. Using adjusted cost-based offers, the markup component of LMP for marginal generating resources increased for coal fired steam units from \$1.08 to \$2.14 per MWh and decreased for gas fired CC units from \$1.48 to \$1.39 per MWh.²⁰²

²⁰² May 21, 2022, HE 1700 (EPT), September 15, 2022, HE 0200 (EPT), September 21, 2022, HE 1500 (EPT), October 24, 2022, HE 0900 (EPT), and November 11, 2022, HE 0700 (EPT) had abnormal unit participant factor (UPF) values and the marginal resources data in that hour was removed from 2022 pricing run data.

Table 3-141 Markup component of day-ahead load-weighted average LMP by primary fuel type and technology type: 2021 and 2022

Fuel	Technology	2021			2022		
		Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency
Coal	Steam	\$0.52	\$1.08	31.5%	\$1.36	\$2.14	22.5%
Gas	CC	\$0.44	\$1.48	53.4%	\$0.96	\$1.39	58.5%
Gas	CT	\$0.02	\$0.05	2.4%	\$1.72	\$3.23	4.3%
Gas	RICE	(\$0.00)	\$0.00	0.9%	(\$0.01)	\$0.01	0.9%
Gas	Steam	(\$0.04)	\$0.01	3.3%	(\$0.11)	\$0.04	3.8%
Municipal Waste	RICE	\$0.00	\$0.00	0.2%	(\$0.00)	(\$0.00)	0.0%
Municipal Waste	Steam	\$0.00	\$0.00	0.0%	(\$0.00)	(\$0.00)	0.0%
Oil	CC	\$0.00	\$0.00	0.0%	\$0.00	\$0.04	0.2%
Oil	CT	\$0.03	\$0.04	0.8%	(\$0.10)	(\$0.37)	1.8%
Oil	RICE	\$0.00	\$0.00	0.1%	\$0.01	\$0.01	0.2%
Oil	Steam	(\$0.09)	(\$0.08)	0.1%	(\$0.00)	\$0.03	0.1%
Other	Solar	\$0.03	\$0.03	0.2%	\$0.25	\$0.25	0.4%
Other	Steam	\$0.00	\$0.00	0.2%	\$0.00	\$0.00	0.1%
Uranium	Steam	\$0.00	\$0.00	0.3%	\$0.00	\$0.00	0.0%
Water	Hydro	\$0.00	\$0.00	0.0%	\$0.00	\$0.00	0.1%
Wind	Wind	\$0.31	\$0.31	6.6%	\$0.40	\$0.40	7.1%
Total		\$1.22	\$2.93	100.0%	\$4.47	\$7.17	100.0%

Markup Component of Day-Ahead Price

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units. Only hours when generating units were marginal on either priced-based offers or on cost-based offers were included in the markup calculation.

Table 3-142 shows the markup component of average prices and of average monthly on peak and off peak prices using unadjusted cost-based offers. In 2022, when using unadjusted cost-based offers, \$4.47 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In 2022, the peak markup component was highest in November, \$9.05 per MWh using unadjusted cost-based offers and the off peak markup component was highest in December, \$31.46 per MWh.

Table 3-142 Monthly markup components of day-ahead (Unadjusted) load-weighted LMP: 2021 and 2022

	2021			2022		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	(\$0.41)	(\$0.19)	(\$0.59)	\$4.44	\$6.17	\$2.85
Feb	(\$0.30)	\$2.25	(\$2.91)	\$1.28	\$1.28	\$1.28
Mar	\$0.62	\$0.56	\$0.69	\$3.45	\$4.86	\$1.92
Apr	\$0.38	\$0.84	(\$0.14)	\$3.90	\$3.44	\$4.35
May	\$1.06	\$1.26	\$0.88	\$2.86	\$5.11	\$0.67
Jun	\$0.16	\$0.41	(\$0.13)	\$4.82	\$7.21	\$1.80
Jul	\$1.97	\$3.19	\$0.65	\$1.27	(\$0.50)	\$2.98
Aug	\$1.59	\$2.32	\$0.73	\$3.51	\$4.79	\$1.92
Sep	\$2.31	\$3.44	\$1.07	\$4.03	\$5.60	\$2.37
Oct	\$4.87	\$8.06	\$1.66	\$3.90	\$6.13	\$1.73
Nov	\$2.36	\$2.12	\$2.60	\$2.10	\$9.05	(\$4.78)
Dec	\$0.37	\$1.23	(\$0.62)	\$17.24	\$1.33	\$31.46
Total	\$1.22	\$2.10	\$0.29	\$4.47	\$4.49	\$4.45

Table 3-143 shows the markup component of average prices and of average monthly on peak and off peak prices using adjusted cost-based offers. In 2022, when using adjusted cost-based offers, \$7.71 per MWh of the PJM day-ahead, load-weighted average LMP was attributable to markup. In 2022, the peak markup component was highest in November, \$30.37 per MWh using adjusted cost-based offers and the off peak markup component was highest in December, \$40.81 per MWh.

Table 3-143 Monthly markup components of day-ahead (Adjusted) load-weighted LMP: 2021 and 2022

	2021			2022		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	\$1.16	\$1.31	\$1.03	\$8.04	\$10.34	\$5.93
Feb	\$2.21	\$4.69	(\$0.33)	\$2.83	\$1.95	\$3.69
Mar	\$1.78	\$1.72	\$1.84	\$6.39	\$8.58	\$4.02
Apr	\$1.64	\$1.98	\$1.26	\$5.93	\$5.32	\$6.55
May	\$2.45	\$2.58	\$2.33	\$5.67	\$7.51	\$3.88
Jun	\$1.49	\$1.75	\$1.19	\$7.42	\$9.51	\$4.77
Jul	\$3.62	\$4.73	\$2.41	\$4.20	\$2.76	\$5.59
Aug	\$3.40	\$3.99	\$2.71	\$6.78	\$7.85	\$5.44
Sep	\$4.25	\$5.13	\$3.29	\$5.44	\$5.42	\$5.45
Oct	\$6.89	\$9.85	\$3.91	(\$1.33)	\$0.44	(\$3.04)
Nov	\$4.44	\$4.11	\$4.77	\$12.01	\$30.37	(\$6.15)
Dec	\$2.07	\$2.92	\$1.11	\$20.98	(\$1.20)	\$40.81
Total	\$2.93	\$3.71	\$2.10	\$7.17	\$7.34	\$7.00

Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted cost-based offers is shown for each zone in Table 3-144. The markup component of annual average day-ahead price using adjusted cost-based offers is shown for each zone in Table 3-145. The smallest zonal all hours average markup component using adjusted cost-based offers for 2022 was in the PPL Zone, -\$2.80 per MWh, while the highest was in the DPL Zone, \$17.30 per MWh. The smallest zonal on peak average markup using adjusted cost-based offers was in the MEC Zone, -\$6.85 per MWh, while the highest was in the DPL Zone, \$46.62 per MWh.

Table 3-144 Day-ahead average zonal markup component (Unadjusted): 2021 and 2022

	2021			2022		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	\$0.88	\$1.44	\$0.29	\$1.95	\$2.33	\$1.57
AEP	\$1.20	\$2.10	\$0.27	\$4.44	\$2.95	\$5.94
APS	\$1.12	\$2.03	\$0.15	\$5.05	\$4.09	\$6.01
ATSI	\$0.89	\$1.56	\$0.18	\$1.97	\$5.48	(\$1.72)
BGE	\$1.75	\$3.15	\$0.30	\$5.55	\$2.46	\$8.65
COMED	\$1.14	\$1.81	\$0.43	\$6.03	\$8.15	\$3.84
DAY	\$1.39	\$2.42	\$0.28	\$5.22	\$3.93	\$6.58
DOM	\$1.50	\$2.53	\$0.45	\$4.65	\$3.68	\$5.60
DPL	\$0.51	\$0.51	\$0.51	\$14.24	\$19.31	\$9.18
DUKE	\$1.30	\$2.23	\$0.33	\$4.70	\$4.32	\$5.10
DUQ	\$0.95	\$1.61	\$0.26	\$3.34	\$3.35	\$3.33
EKPC	\$2.32	\$4.48	\$0.15	\$3.78	\$4.01	\$3.56
JCPLC	\$0.85	\$1.38	\$0.25	\$3.49	\$2.26	\$4.81
MEC	\$1.04	\$1.79	\$0.21	\$0.36	(\$2.46)	\$3.38
OVEC	\$1.24	\$1.76	\$0.72	\$2.79	\$3.01	\$2.55
PE	\$0.79	\$1.30	\$0.20	\$8.31	\$11.56	\$4.67
PECO	\$0.73	\$1.08	\$0.36	\$5.13	\$2.41	\$7.94
PEPCO	\$1.59	\$2.79	\$0.29	\$5.19	\$1.87	\$8.71
PPL	\$0.86	\$1.39	\$0.29	(\$1.45)	\$4.22	(\$7.31)
PSEG	\$0.84	\$1.31	\$0.33	\$4.59	\$3.05	\$6.20
REC	\$0.84	\$1.37	\$0.23	\$2.14	\$1.93	\$2.38

Table 3-145 Day-ahead average zonal markup component (Adjusted): 2021 and 2022

	2021			2022		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	\$2.80	\$3.36	\$2.22	\$2.98	\$4.99	\$0.98
AEP	\$2.93	\$3.74	\$2.08	\$7.44	\$5.66	\$9.23
APS	\$2.90	\$3.73	\$2.03	\$8.19	\$6.40	\$10.01
ATSI	\$2.73	\$3.30	\$2.12	\$4.99	\$7.36	\$2.49
BGE	\$3.52	\$4.75	\$2.22	\$8.42	\$3.76	\$13.10
COMED	\$2.83	\$3.56	\$2.06	\$9.25	\$10.97	\$7.48
DAY	\$3.24	\$4.19	\$2.20	\$8.36	\$6.29	\$10.57
DOM	\$3.27	\$4.14	\$2.38	\$7.66	\$5.83	\$9.45
DPL	\$2.21	\$2.27	\$2.14	\$17.30	\$46.62	(\$11.96)
DUKE	\$3.02	\$3.81	\$2.17	\$7.75	\$6.96	\$8.58
DUQ	\$2.74	\$3.30	\$2.15	\$6.29	\$5.54	\$7.06
EKPC	\$3.29	\$4.86	\$1.72	\$6.79	\$6.75	\$6.82
JCPLC	\$2.78	\$3.31	\$2.19	\$5.76	\$4.83	\$6.75
MEC	\$2.69	\$3.33	\$1.98	(\$0.83)	(\$6.85)	\$5.60
OVEC	\$3.15	\$3.54	\$2.75	\$4.95	\$5.46	\$4.37
PE	\$2.54	\$3.00	\$2.02	\$8.35	\$8.70	\$7.97
PECO	\$2.57	\$2.93	\$2.18	\$8.08	\$4.83	\$11.45
PEPCO	\$3.38	\$4.45	\$2.23	\$8.00	\$3.23	\$13.07
PPL	\$2.59	\$3.07	\$2.08	(\$2.80)	\$5.27	(\$11.12)
PSEG	\$2.73	\$3.20	\$2.22	\$7.10	\$5.51	\$8.76
REC	\$2.64	\$3.16	\$2.04	\$3.32	\$3.49	\$3.12

Markup by Day-Ahead Price Levels

Table 3-146 and Table 3-147 show the average markup component of LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range.

Table 3-146 Day-ahead average markup component (By LMP category, unadjusted): 2021 and 2022

LMP Category	2021		2022	
	Average Markup Component	Frequency	Average Markup Component	Frequency
\$10 to \$15	(\$0.00)	0.1%	\$0.00	0.0%
\$15 to \$20	\$0.02	8.7%	(\$0.00)	0.3%
\$20 to \$25	(\$0.08)	20.0%	(\$0.01)	0.4%
\$25 to \$50	\$0.41	51.5%	\$0.27	29.3%
\$50 to \$75	\$0.57	15.8%	\$0.93	37.9%
\$75 to \$100	\$0.22	2.9%	\$1.14	16.0%
\$100 to \$125	\$0.03	0.6%	\$0.47	8.8%
\$125 to \$150	(\$0.00)	0.3%	\$0.37	3.2%
>= \$150	\$0.04	0.1%	\$1.31	4.1%

Table 3-147 Day-ahead average markup component (By LMP category, adjusted): 2021 and 2022

LMP Category	2021		2022	
	Average Markup Component	Frequency	Average Markup Component	Frequency
\$10 to \$15	(\$0.00)	0.1%	\$0.00	0.0%
\$15 to \$20	\$0.10	8.7%	(\$0.00)	0.3%
\$20 to \$25	\$0.19	20.0%	(\$0.00)	0.4%
\$25 to \$50	\$1.34	51.5%	\$0.83	29.3%
\$50 to \$75	\$0.90	15.8%	\$1.59	37.9%
\$75 to \$100	\$0.27	2.9%	\$0.72	16.0%
\$100 to \$125	\$0.05	0.6%	\$0.74	8.8%
\$125 to \$150	\$0.01	0.3%	\$0.45	3.2%
>= \$150	\$0.05	0.1%	\$1.68	4.1%

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 that 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:²⁰³

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

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 -0.4.²⁰⁴ 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 1000:²⁰⁵

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

With knowledge of HHI, elasticity, and marginal cost, one can solve for the price level theoretically indicated by the Lerner Index, based on profit maximizing behavior including the exercise of market power. With marginal costs of \$76.81 per MWh and an average HHI of 700 in 2022, average PJM prices would theoretically range from \$93 to \$118 per MWh, an implied markup of 17.5 to 35.0 percent, using the elasticity range of -0.2 to -0.4.²⁰⁶ 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 \$80.14 per MWh with markups at 4.2 percent, are lower than the theoretical range, supporting the MMU's competitive assessment of the market. However, markup is not zero. In some market intervals, markup and prices reach levels that reflect the exercise of market power.

²⁰³ See Tirole, Jean. *The Theory of Industrial Organization*, MIT (1988), Chapter 5: Short-Run Price Competition.

²⁰⁴ 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>>.

²⁰⁵ 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.

²⁰⁶ The average HHI is found in Table 3-D-1. Marginal costs are the sum of all components of LMP except markup, as shown in Table 3-B-60.

Market Power Mitigation and Markup

Fully effective market power mitigation would not allow a seller that fails the structural market power test (the TPS test) to set prices with a positive markup. With the flaws in PJM's implementation of the TPS test, resources can and do set prices with a positive markup while failing the TPS test.

Table 3-148 categorizes day-ahead and real-time marginal unit intervals by markup level and TPS test status. In 2022, 5.8 percent of real-time marginal unit intervals and 6.4 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 3-148 Percent of real-time marginal unit intervals with markup and local market power: 2022

Markup Category	Day-ahead Market			Real-time Market		
	Not Failing TPS Test	Failing TPS Test	Percent in Category	Not Failing TPS Test	Failing TPS Test	Percent in Category
Negative Markup	22.3%	4.1%	26.4%	30.8%	7.9%	38.7%
Zero Markup	15.7%	4.8%	20.5%	15.2%	8.5%	23.7%
\$0 to \$5	12.3%	1.4%	13.6%	15.5%	3.0%	18.5%
\$5 to \$10	7.6%	1.1%	8.6%	6.1%	0.8%	6.9%
\$10 to \$15	6.6%	0.9%	7.5%	2.9%	0.4%	3.4%
\$15 to \$20	5.2%	0.6%	5.8%	2.5%	0.3%	2.8%
\$20 to \$25	4.5%	0.5%	5.0%	1.5%	0.2%	1.8%
\$25 to \$50	7.3%	1.1%	8.3%	2.4%	0.5%	2.9%
\$50 to \$75	2.2%	0.5%	2.7%	0.5%	0.2%	0.7%
\$75 to \$100	0.6%	0.1%	0.8%	0.2%	0.1%	0.3%
Above \$100	0.5%	0.1%	0.6%	0.2%	0.2%	0.4%
Total Positive Markup	46.7%	6.4%	53.1%	31.9%	5.8%	37.7%
Total	84.8%	15.2%	100.0%	77.9%	22.1%	100.0%

The markup of marginal units was zero or negative in 62.4 percent of real-time marginal unit intervals and 46.9 percent of day-ahead marginal unit intervals in 2022. 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 2022. The 46.7 percent of day-ahead marginal units and 31.9 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.

