Ancillary Service Markets

FERC defined six ancillary services in Order No. 888: scheduling, system control and dispatch; reactive supply and voltage control from generation service; regulation and frequency response service; energy imbalance service; operating reserve - synchronized reserve service; and operating reserve - supplemental reserve service.[1] PJM provides scheduling, system control and dispatch, and reactive on a cost basis. PJM provides regulation, energy imbalance, synchronized reserve, and supplemental reserve services through market mechanisms.[2] Although not defined by FERC as an ancillary service, black start service plays a comparable role. Black start service is provided on the basis of formula rates.

PJM implemented significant reserve market changes on October 1, 2022. This *2022 Annual State of the Market Report for PJM* includes nine months of results based on the prior rules and three months of results based on the rules implemented on October 1.[3]

The MMU analyzed measures of market structure, conduct and performance for the PJM tier 2 Synchronized Reserve Market for the first nine months of 2022.

Table 10-1 The tier 2 synchronized reserve market results were competitive: January through September, 2022

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Mixed

- The tier 2 synchronized reserve market structure was evaluated as not competitive because of high levels of supplier concentration.
- Participant behavior was evaluated as competitive because the market rules required cost-based offers.
- Market performance was evaluated as competitive because the interaction of participant behavior with the market design resulted in competitive prices.
- Market design was evaluated as mixed. Market power mitigation rules resulted in competitive outcomes despite high levels of supplier concentration. However, tier 1 reserves were inappropriately overcompensated when the nonsynchronized reserve market cleared with a nonzero price. This settlement rule was removed on October 1, 2022, with the consolidation of tier 1 and tier 2 reserves.

The MMU analyzed measures of market structure, conduct and performance for the PJM Synchronized Reserve Market for the last three months of 2022.

Table 10-2 The synchronized reserve market results were competitive: October through December, 2022

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Effective

- The synchronized reserve market structure was evaluated as not competitive due to moderate and high levels of supplier concentration.
- Participant behavior was evaluated as competitive because the market rules require all available reserves to offer at cost-based offers.
- Market performance was evaluated as competitive because the interaction of participant behavior with the market design results in competitive prices.
- Market design was evaluated as effective. PJM adopted reforms, including several based on MMU recommendations, removing both physical and economic withholding from the market.

The MMU analyzed measures of market structure, conduct and performance for the PJM DASR Market for the first nine months of 2022.

Table 10-3 The day-ahead scheduling reserve market results were competitive: January through September, 2022

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Mixed	
Market Performance	Competitive	Mixed

- The DASR market structure was evaluated as not competitive because the DASR market failed the three pivotal supplier (TPS) test in 86.7 percent of the intervals in which the price was greater than $0.01 per MWh.
- Participant behavior was evaluated as mixed because while most offers were equal to marginal costs, a significant proportion of offers reflected

1 75 FERC ¶ 61,080 (1996).
2 Energy imbalance service refers to the real-time energy market.
3 The past tense is used when describing the rules in place during the first nine months of 2022 to reflect the perspective of the report after October 1, 2022.

economic withholding. The ability to withhold 30 minute reserves using offers was removed on October 1, 2022, with the implementation of a secondary reserve market.

- Market performance was evaluated as competitive because there were adequate offers in every hour to satisfy the requirement and the clearing prices reflected in those offers, although there was concern about offers above the competitive level affecting prices. The day-ahead scheduling reserve market clearing price was above $0 in 12.6 percent of hours in the first nine months of 2022. In 98.4 percent of hours when the clearing price was above $0, the clearing price was the offer price of the marginal unit. The price included lost opportunity cost in 1.6 percent of hours when the clearing price was above $0. After October 1, 2022, clearing prices for 30 minute reserves include only lost opportunity cost.
- Market design was evaluated as mixed because the DASR product did not include performance obligations. Offers should be based on opportunity cost only, to ensure competitive outcomes and that market power cannot be exercised. After October 1, 2022, offers only contain opportunity cost and day-ahead 30 minute reserves have a corresponding real-time product.

The MMU analyzed measures of market structure, conduct and performance for the PJM Secondary Reserve Market for the last three months of 2022.

Table 10-4 The secondary reserve market results were competitive: October through December, 2022

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Effective

- The secondary reserve market structure was evaluated as competitive, because the supply of 30 minute reserves is not concentrated.
- Participant behavior was evaluated as competitive because all available reserves are deemed as offered in the PJM software, so withholding is not possible.
- Market performance was evaluated as competitive because the combination of a competitive market structure and competitive participation resulted in competitive market outcomes.
- The market design was evaluated as effective because the market rules ensure competitive market offers and require repayment of offline cleared secondary reserves that are not available when called on to provide energy in 30 minutes.

The MMU analyzed measures of market structure, conduct and performance for the PJM Regulation Market for 2022.

Table 10-5 The regulation market results were not competitive

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Not Competitive	Flawed

- The regulation market structure was evaluated as not competitive because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 89.1 percent of the hours in 2022.
- Participant behavior in the PJM Regulation Market was evaluated as competitive in 2022 because market power mitigation requires competitive offers when the three pivotal supplier test is failed, although the inclusion of a positive margin raises questions.
- Market performance was evaluated as not competitive, because all units are not paid the same price on an equivalent MW basis.
- Market design was evaluated as flawed. The market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost. The result is significantly flawed market signals to existing and prospective suppliers of regulation.

Overview

Primary Reserve

Primary reserves consist of both synchronized and nonsynchronized reserves that can provide energy within ten minutes and sustain that output for at least 30 minutes during a contingency event. PJM made several changes to the primary reserve market, effective October 1, 2022. These included a must offer requirement and correction of misspecified cost-based offers. By removing opportunities for physical and economic withholding, the changes resulted in clearing increased quantities of available synchronized reserves at competitive prices.

In the first nine months of 2022, the synchronized reserve market included both tier 1 and tier 2 synchronized reserves. Tier 1 reserves incurred no cost for making reserves available to the market and did not receive compensation through the clearing price. Tier 2 reserves incurred lost opportunity costs or explicit costs to provide reserves and received payment through the market clearing price. Tier 1 and tier 2 reserves were substitutes, so the two were combined into a single product receiving the same compensation on October 1, 2022.

Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (generation or demand response currently synchronized to the grid and available within 10 minutes), and nonsynchronized reserve (generation currently off line but available to start and provide energy within 10 minutes).
- **Demand.** The PJM primary reserve requirement is 150 percent of the largest single contingency plus 190 MW. In 2022, the average primary reserve requirement was 2,473.4 MW in the RTO Zone and 2,472.5 in the MAD Subzone.

Tier 1 Synchronized Reserve (prior to October 1, 2022)

Synchronized reserve is provided by generators and demand response resources synchronized to the grid and capable of increasing output or decreasing load within 10 minutes in response to a PJM declared synchronized reserve event. Before the reserve market changes implemented on October 1, 2022, synchronized reserve consisted of tier 1 and tier 2 synchronized reserves.

Tier 1 synchronized reserve was defined as the capability of online resources following economic dispatch to ramp up in 10 minutes from their current output in response to a synchronized reserve event. Every real-time market solution calculated the available tier 1 synchronized reserve. There was never a formal market for tier 1 synchronized reserve.

- **Supply.** No offers were made for tier 1 synchronized reserves. The market solution estimated tier 1 synchronized reserve as available 10 minute ramp from the energy dispatch. In the first nine months of 2022, there was an average hourly supply of 1,531.4 MW of tier 1 available in the RTO Zone and an average hourly supply of 693.6 MW of tier 1 synchronized reserve available within the MAD Subzone.
- **Demand.** The synchronized reserve requirement is calculated for each real-time dispatch solution as the largest single contingency plus 190 MW within both the RTO Zone and the MAD Subzone.
- **Tier 1 Synchronized Reserve Event Response.** Tier 1 synchronized reserve was paid when a synchronized reserve event occurred and it responded. When a synchronized reserve event was called, all tier 1 response was paid for increasing its output (or reducing load for demand response) at the rate of $50 per MWh in addition to LMP.[4] This was called the synchronized energy premium price.
- **Issues.** The competitive offer for tier 1 synchronized reserves was zero, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point and the appropriate payment for responding to an event was the synchronized energy premium price of $50 per MWh. The tariff required payment of the tier 2 synchronized reserve market clearing price to tier 1 resources whenever the nonsynchronized reserve market clearing price rose above zero. This requirement was unnecessary and inconsistent with efficient markets. This rule had a significant impact on the cost of tier 1 synchronized reserves, resulting in a windfall payment of more than $150 million from 2014 to 2022. In the first nine months of 2022, the nonsynchronized reserve market clearing price was above $0 in 609 intervals, none of which were during a spinning event. Both the synchronized reserve premium price and the payment when the nonsynchronized reserve price was above zero were removed on October 1, 2022.

Tier 2 Synchronized Reserve Market (prior to October 1, 2022)

Tier 2 synchronized reserve was part of primary reserve and was comprised of resources that were synchronized to the grid, that may have incurred costs to be synchronized, and that had an obligation to

4 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements, Rev. 122 (Oct. 1, 2022).

respond to PJM declared synchronized reserve events. Tier 2 synchronized reserve was penalized for failure to respond to a PJM declared synchronized reserve event. Tier 2 synchronized reserve, along with tier 1, was replaced by the new consolidated synchronized reserve on October 1, 2022, which behaves similarly to tier 2. In PJM, the required amount of synchronized reserve is defined to be no less than the largest single contingency, and 10 minute primary reserve as no less than 150 percent of the largest single contingency, plus 190 MW. This is stricter than the NERC standard of the greater of 80 percent of the largest single contingency or 900 MW.[5]

When the synchronized reserve requirement could not be met with tier 1 synchronized reserve alone, PJM used the tier 2 synchronized reserve market to satisfy the balance of the requirement. The tier 2 synchronized reserve market included the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve Subzone (MAD).

Market Structure

- **Supply.** In the first nine months of 2022, the average supply of daily offered and eligible tier 2 synchronized reserve was 35,042.6 MW in the RTO Zone of which 5,478.1 MW was located in the MAD Subzone.
- **Demand.** The average hourly synchronized reserve requirement was 1,676.2 MW in the RTO Reserve Zone and 1,675.5 in the Mid-Atlantic Dominion Reserve Subzone. The hourly average cleared tier 2 synchronized reserve was 234.5 MW in the MAD Subzone and 706.4 MW in the RTO.
- **Market Concentration.** Both the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market and the RTO Synchronized Reserve Zone Market were characterized by structural market power in the first nine months of 2022.

  The average HHI for tier 2 synchronized reserve in the RTO Zone was 2898 which is classified as highly concentrated.

Market Conduct

- **Offers.** There was a must offer requirement for tier 2 synchronized reserve. All nonemergency generation capacity resources were required to submit a daily offer for tier 2 synchronized reserve, unless the unit type was exempt. Tier 2 synchronized reserve offers from generating units were subject to an offer cap of marginal cost plus $7.50 per MW, plus opportunity cost which was calculated by PJM. PJM automatically entered an offer of $0 for tier 2 synchronized reserve when an offer was not entered by the owner. Demand resources offering into the tier 2 market were also subject to an offer cap of $7.50 plus costs. Cost could include shutdown costs for demand response.[6]

Market Performance

- **Price.** The weighted average price for tier 2 synchronized reserve for all cleared hours in the MAD Subzone was $18.14 per MW in the first nine months of 2022. The weighted average price for tier 2 synchronized reserve for all cleared intervals in the RTO Synchronized Reserve Zone was $16.16 per MW in the first nine months of 2022.

Synchronized Reserve Market (since October 1, 2022)

Synchronized reserves include all capacity synchronized to the grid and available to satisfy PJM's power balance within ten minutes. This includes online resources loaded below their full output, storage or condensing resources synchronized to the grid but consuming energy, and ten minute demand response capability. As of October 1, 2022, all generation capacity resources must offer their full synchronized reserve capability to the PJM market at all times. PJM jointly optimizes energy, synchronized reserve, primary reserve, and secondary reserve needs in both the day-ahead and real-time markets. Synchronized reserve prices are based on opportunity costs calculated by PJM in the market optimization and the anticipated cost of a performance penalty. All real-time cleared synchronized reserves are obligated to perform when PJM initiates a synchronized reserve event based on a loss of supply.

5 NERC (June 2, 2020) <NERC Reliability Standard BAL 002-2 Glossary_of_Terms.pdf>.

6 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 122 (Oct. 1, 2022).

Market Structure

- **Supply.** In the last three months of 2022, the average supply of daily offered and eligible synchronized reserve was 7,342.6 MW in the RTO Zone of which 3,570.0 MW was located in the MAD Subzone.
- **Demand.** The average hourly synchronized reserve requirement in the last three months of 2022 was 1,819.0 MW in the RTO Reserve Zone and 1,818.8 in the Mid-Atlantic Dominion Reserve Subzone.
- **Market Concentration.** Both the Mid-Atlantic Dominion Subzone and the RTO Synchronized Reserve Zone Market were characterized by structural market power in the last three months of 2022. The average HHI for real-time synchronized reserve in the RTO Zone was 868, which is classified as unconcentrated. The average HHI for day-ahead synchronized reserve in the RTO Zone was 1043, which is classified as concentrated. The average HHI for real-time synchronized reserve in the MAD Subzone was 3257, which is classified as highly concentrated. The average HHI for day-ahead synchronized reserve in the MAD Subzone was 2410, which is classified as concentrated.

Market Conduct

- **Offers.** There is a must offer requirement for synchronized reserve. All nonemergency generation capacity resources are required to offer their full synchronized reserve capability. PJM automatically calculates the available synchronized reserve for all conventional resources based on the energy offer ramp rate, energy dispatch point, and the lesser of the synchronized reserve maximum or economic maximum output. Hydro resources, energy storage resources, and demand response resources submit their available synchronized reserve MW offers. Wind, solar, and nuclear resources are by default considered incapable of providing synchronized reserve, but may offer with an exception approved by PJM. Synchronized reserve offers are capped at cost plus the expected value of performance penalties. PJM calculates opportunity costs based on LMP.

Market Performance

- **Price.** The weighted average price for synchronized reserve for all cleared market intervals in the MAD Subzone was $17.12 per MWh in the last three months of 2022. The weighted average price for synchronized reserve for all cleared intervals in the RTO Synchronized Reserve Zone was $11.21 per MWh in the last three months of 2022.

Nonsynchronized Reserve Market

Nonsynchronized reserve is comprised of nonemergency energy resources not currently synchronized to the grid that can provide energy within 10 minutes. Nonsynchronized reserve is available to meet the primary reserve requirement above the synchronized reserve requirement.

The October 1, 2022, changes to the reserve markets included the removal of lost opportunity costs from pricing and settlements for nonsynchronized reserves, because offline units that have not been called to operate by PJM do not have a lost opportunity cost. PJM also removed the ability for emergency resources to participate in the nonsynchronized reserve market under special arrangements with PJM.

Market Structure

- **Supply.** In 2022, the average supply of eligible and available nonsynchronized reserve was 1,659.4 MW in the RTO Zone.
- **Demand.** Demand for nonsynchronized reserve is the primary reserve requirement, which is satisfied jointly by synchronized and nonsynchronized reserves.[7]
- **Market Concentration.** The average HHI for 2022 for nonsynchronized reserves in the RTO Zone was 1123, which is classified as concentrated. The average HHI for 2022 for nonsynchronized reserves in the MAD Subzone was 1952, which is classified as highly concentrated.

Market Conduct

- **Offers.** Generation owners do not submit supply offers for nonsynchronized reserve. Nonemergency generation resources that are available to provide energy and can start in 10 minutes or less are defined

7 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.1 Overview of the PJM Reserve Markets, Rev. 122 (Oct. 1, 2022).

to be available for nonsynchronized reserves. PJM calculated the associated offer prices based on PJM calculations of resource specific opportunity costs prior to October 1, 2022. The reserve market design implemented on October 1, 2022, removed the PJM estimated nonsynchronized reserve opportunity cost calculation because offline resources do not have an opportunity cost for the market intervals when they are scheduled to be offline because PJM cannot dispatch them for energy in those intervals.[8]

Market Performance

- **Price.** The nonsynchronized reserve price is determined by the marginal primary reserve resource. The nonsynchronized reserve weighted average price for all intervals in the RTO Reserve Zone was $0.32 per MWh in the first nine months of 2022. The nonsynchronized reserve weighted average price for all intervals in the RTO Reserve Zone was $1.74 per MWh in the last three months of 2022. The nonsynchronized reserve weighted average price for all intervals in the MAD Reserve Subzone was $6.07 per MWh in the last three months of 2022.

Day-Ahead Scheduling Reserve (prior to October 1, 2022)

In the first nine months of 2022, PJM maintained a day-ahead, offer-based market for 30 minute day-ahead secondary reserve. The PJM Day-Ahead Scheduling Reserve Market (DASR) had no performance obligations except that a unit that cleared the DASR market could not be on an outage in real time.[9] If DASR units were on an outage in real time or cleared DASR MW were not available, the DASR payment was not made.

Market Structure

- **Supply.** The DASR market was a must offer market. Any resources that did not make an offer had their offer set to $0.00 per MW. DASR was calculated by the day-ahead market solution as the lesser of the 30 minute energy ramp rate or the economic maximum MW minus the day-ahead dispatch point for all resources that could provide energy within 30 minutes of a request from PJM Dispatch.
- **Demand.** The DASR requirement was the sum of the PJM requirement and the Dominion requirement based on the VACAR reserve sharing agreement. It was calculated every year for the period November 1 through October 31. For November 1, 2021, through October 31, 2022, the DASR requirement was 4.40 percent of forecast peak load. The average hourly DASR MW purchased in the first nine months of 2022 was 4,820.4 MW, a decrease from the 5,094.2 hourly MW in the first nine months of 2021.

Market Conduct

- **Withholding.** Economic withholding was an issue in the DASR Market. The direct marginal cost of providing DASR was zero. PJM calculated the opportunity cost for each resource. All offers by resource owners greater than zero constituted economic withholding. In the first nine months of 2022, 43.7 percent of daily unit offers were above $0.00 and 16.9 percent of daily unit offers were above $5.
- **DR.** Demand resources were eligible to participate in the DASR Market. Some demand resources entered offers for DASR. No demand resources cleared the DASR market in the first nine months of 2022.

Market Performance

- **Price.** In the first nine months of 2022, the MW weighted average DASR price for all hours when the DASRMCP was above $0.00 was $2.28. The MW weighted average for all hours including hours when the price was $0 was $0.37.

Secondary Reserve Market (since October 1, 2022)

On October 1, 2022, PJM introduced a new 30 minute reserves requirement. Secondary reserves are the reserves that take more than 10 minutes to convert to energy, but less than 30 minutes. This includes the unloaded capacity of online generation that can be achieved according to the resource ramp rates in 10 to 30 minutes. It also includes offline resources that offer a time to start of less than 30 minutes.

8 See *PJM Interconnection, L.L.C.*, "Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C.," Docket No. EL19-58 (March 29, 2019) at 84.
9 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 11.2.7 Day-Ahead Scheduling Reserve Performance, Rev. 122 (Oct. 1, 2022).

Market Structure

Supply. In the last three months of 2022, the average cleared 30 minute reserves was 12,608.9 MW in the day-ahead market and 4,264.5 MW in the real-time market. Unlike the day-ahead market, the real-time market did not clear all available 30 minute reserves.

Demand. As of October 1, 2022, the 30-minute reserve requirement is the maximum of: 150 percent of the synchronized reserve requirement (the same as for primary reserve); the largest active gas contingency; or 3,000 MW.

Market Concentration. The 30 minute reserve market was unconcentrated in the last three months of 2022. The HHI for real-time 30 minute reserves was 527. The HHI for day-ahead 30 minute reserves was 882.

Market Behavior

Effective October 1, 2022, PJM has both day-ahead and real-time 30 minute reserves markets using only lost opportunity costs to determine price, not submitted offers. The offer price of offline secondary reserve is $0.00. For online secondary reserves, PJM calculates an opportunity cost based on LMP.

Market Performance

The average day-ahead price for secondary reserves in the last three months of 2022 was $0.00 per MWh. The average real-time price for secondary reserves in the last three months of 2022 was $0.12 per MWh.

Regulation Market

The PJM Regulation Market is a real-time market. Regulation is provided by generation resources and demand response resources that qualify to follow one of two regulation signals, RegA or RegD. PJM jointly optimizes regulation with synchronized reserve and energy to provide all three products at least cost. The PJM regulation market design includes three clearing price components: capability; performance; and opportunity cost. The RegA signal is designed for energy unlimited resources with physically constrained ramp rates. The RegD signal is designed for energy limited resources with fast ramp rates. In the regulation market RegD MW are converted to effective MW using a marginal rate of technical substitution (MRTS), called a marginal benefit factor (MBF). Correctly implemented, the MBF would be the marginal rate of technical substitution (MRTS) between RegA and RegD, holding the level of regulation service constant. The current market design is critically flawed as it has not properly implemented the MBF as an MRTS between RegA and RegD resource MW and the MBF has not been consistently applied in the optimization, clearing and settlement of the regulation market.

Market Structure

- **Supply.** In 2022, the average hourly offered supply of regulation for nonramp hours was 746.7 performance adjusted MW (756.4 effective MW). This was an increase of 5.9 performance adjusted MW (an increase of 11.5 effective MW) from 2021. In 2022, the average hourly offered supply of regulation for ramp hours was 1,101.6 performance adjusted MW (1,110.3 effective MW). This was an increase of 35.3 performance adjusted MW (an increase of 15.4 effective MW) from 2021, when the average hourly offered supply of regulation was 1,066.4 performance adjusted MW (1,094.9 effective MW).
- **Demand.** The hourly regulation demand is 525.0 effective MW for nonramp hours and 800.0 effective MW for ramp hours.
- **Supply and Demand.** The nonramp regulation requirement of 525.0 effective MW was provided by a combination of cleared RegA and RegD resources equal to 465.0 hourly average performance adjusted actual MW in 2022. This is an increase of 16.6 performance adjusted actual MW from 2021, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 481.6 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of cleared RegA and RegD resources equal to 715.0 hourly average performance adjusted actual MW in 2022. This is an increase of 7.6 performance adjusted actual MW from 2021, where the average hourly regulation cleared MW for ramp hours were 707.3 performance adjusted actual MW.

  The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 1.60 in 2022 (1.54 in 2021). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.54 in 2022 (1.51 in 2021).

- **Market Concentration.** In 2022, the three pivotal supplier test was failed in 89.1 percent of hours. In 2022, the effective MW weighted average HHI of RegA resources was 2459 which is highly concentrated and the effective MW weighted average HHI of RegD resources was 1679 which is moderately concentrated. The effective MW weighted average HHI of all resources was 1416, which is moderately concentrated.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost-based offer and may submit a price-based offer. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.[10] In 2022, there were 203 resources following the RegA signal and 54 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $53.53 per MW of regulation in 2022, an increase of $27.52 per MW, or 105.8 percent, from the weighted average clearing price of $26.00 per MW in 2021. The weighted average cost of regulation in 2022 was $65.10 per MW of regulation, an increase of 106.8 percent, from the weighted average cost of $31.49 per MW in 2021.
- **Prices.** RegD resources continue to be incorrectly compensated relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment and settlement processes. If the regulation market were functioning efficiently and competitively, RegD and RegA resources would be paid the same price per effective MW.
- **Marginal Benefit Factor.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor is incorrectly defined and applied in the PJM market clearing. The current incorrect and inconsistent implementation of the MBF has resulted in the PJM Regulation Market over procuring RegD relative to RegA in most hours and in an inefficient market signal about the value of RegD in every hour.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[11]

In 2022, total black start charges were $68.6 million, including $68.1 million in revenue requirement charges and $0.5 million in uplift charges. Black start revenue requirements consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive payment. Black start uplift charges are paid to units scheduled in the day-ahead energy market or committed in real time to provide black start service under the ALR option or for black start testing. Black start zonal charges in 2022 ranged from $0 in the OVEC and REC Zones to $19.6 million in the AEP Zone.

CRF values are a key determinant of total payments to black start units. The CRF values in PJM tariff tables should have been changed for both black start and the capacity market when the tax laws changed in December 2017. As a result of the failure to change the CRF values, black start units have been and continue to be significantly overcompensated since the changes to the tax code.

Reactive

Reactive service, reactive supply and voltage control are provided by generation and other sources of reactive power (measured in MVAr). Reactive power helps maintain appropriate voltage levels on the transmission system and is essential to the flow of real power (measured in MW). The same equipment provides both MVAr and MW. Generation resources are required to meet defined reactive capability requirements as a condition to receive interconnection service in PJM.[12] RTOs and their customers are not required to compensate generation

10 See the *2021 State of the Market Report for PJM*, Vol. II, Appendix F "Ancillary Services Markets."

11 OATT Schedule 1 § 1.3BB. There are no ALR units currently providing black start service.

12 OATT Attachment O.

resources for such reactive capability.[13] Customers in PJM, nevertheless, pay $384.0 million in nonmarket costs for reactive capability based on a nonmarket view of cost allocation. The current rules permit over recovery of capital costs through reactive capability charges. All capacity costs of generators should be incorporated in the market. The nonmarket approach to reactive capability payments should be eliminated.

Reactive capability charges are based on FERC approved filings for individual unit revenue requirements that are typically black box settlements.[14] Reactive service charges are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive service.

Total reactive charges in 2022 increased 5.4 percent from $365.6 million in 2021 to $385.5 million in 2022. In 2022, reactive capability charges increased 5.3 percent from $364.7 million in the 2021 to $384.0 million in 2022. Total reactive service charges in 2022 ranged from $0 in the REC and OVEC Zones, to $52.8 million in the AEP Zone.

Frequency Response

The PJM Tariff requires that all new generator interconnection customers, both synchronous and nonsynchronous, have hardware and/or software that provides primary frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust real power output to correct for frequency deviations.[15] Primary frequency response begins within a few seconds and extends up to a minute. The purpose of primary frequency response is to arrest and stabilize the system until other measures (secondary and tertiary frequency response) become active. This includes a governor or equivalent controls capable of operating with a maximum five percent droop and a +/- 36 mHz deadband.[16] In addition to resource capability, resource owners must comply by setting control systems to autonomously adjust real power output in a direction to correct for frequency deviations.

The response of generators within PJM to NERC identified frequency events remains under evaluation. A frequency event is declared whenever the system frequency goes outside of 60 Hz by +/- 40 mHz and stays there for 60 continuous seconds. The NERC BAL-003-2 requirement for balancing authorities (PJM is a balancing authority) uses a threshold value (L_{10}) equal to -259.3 MW/0.1 Hz and has selected twelve frequency events between December 1, 2020, and November 30, 2021, to evaluate.

As a balancing authority, PJM requires all generators to be capable of providing primary frequency response and to operate with primary frequency response controls enabled.[17] PJM does monitor primary frequency response during NERC identified frequency events for all resources 50 MW or greater. Exclusions to PJM monitoring include nuclear plants, offline units, units with no available headroom, units assigned to regulation, and units with a current outage ticket in eDART.

Ancillary Services Costs per MWh of Load

Table 10-6 shows PJM ancillary services costs for 1999 through 2022, per MWh of load. The rates are calculated as the total charges for the specified ancillary service divided by the total PJM real-time load in MWh.[18] The scheduling, system control, and dispatch category of costs is comprised of PJM scheduling, PJM system control and PJM dispatch; owner scheduling, owner system control and owner dispatch; other supporting facilities; black start services; direct assignment facilities; and Reliability*First* Corporation charges. The cost per MWh of load in Table 10-6 is a different metric than the cost of each ancillary service per MW of that service. The cost per MWh of load includes the effects both of price changes per MW of the ancillary service and changes in total load.

13 *See* 182 FERC ¶ 61,033 at P 52 (January 27, 2023); *see also Standardization of Generator Interconnection Agreements & Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at P 546 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 at P 28, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. National Association of Regulatory Utility Commissioners v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007); California ISO, 160 FERC ¶ 61,035 at P 19 (2017); 119 FERC ¶ 61,199 at P 28 (2007), *order on reh'g*, 121 FERC ¶ 61,196 (2007); *see also* 178 FERC ¶ 61,088, at PP 29–31 (2022); 179 FERC ¶ 61,103, at PP 20-21 (2022).

14 OATT Schedule 2.

15 Nuclear Regulatory Commission (NRC) regulated facilities are exempt from this provision. Behind the meter generation that is sized to load is also exempt.

16 OATT Attachment O § 4.7.2 (Primary Frequency Response).

17 *Id.*; see also "PJM Manual 12: Balancing Operations, Rev. 47 (Oct. 1, 2022). § 3.6 (Primary Frequency Response).

18 The total prices in this table are a load-weighted average system price per MWh by category, even if each category is not charged on that basis. These totals are presented for informational purposes and should not be used to calculate the costs of any specific market activity in PJM.

Table 10-6 History of ancillary services costs per MWh of load: 1999 through 2022[19] [20]

Year	Regulation	Scheduling, Dispatch and System Control	Reactive	Synchronized Reserve	Total
1999	$0.15	$0.23	$0.26	$0.00	$0.64
2000	$0.39	$0.26	$0.29	$0.00	$0.94
2001	$0.53	$0.71	$0.22	$0.00	$1.46
2002	$0.42	$0.86	$0.20	$0.01	$1.49
2003	$0.50	$1.05	$0.24	$0.15	$1.94
2004	$0.51	$0.93	$0.26	$0.13	$1.83
2005	$0.80	$0.72	$0.26	$0.11	$1.89
2006	$0.53	$0.74	$0.29	$0.08	$1.64
2007	$0.63	$0.72	$0.29	$0.06	$1.70
2008	$0.70	$0.38	$0.34	$0.08	$1.50
2009	$0.34	$0.29	$0.36	$0.05	$1.04
2010	$0.36	$0.35	$0.45	$0.07	$1.23
2011	$0.32	$0.36	$0.41	$0.09	$1.18
2012	$0.26	$0.41	$0.46	$0.04	$1.17
2013	$0.25	$0.41	$0.76	$0.04	$1.46
2014	$0.33	$0.42	$0.40	$0.12	$1.27
2015	$0.23	$0.42	$0.37	$0.11	$1.13
2016	$0.11	$0.41	$0.38	$0.05	$0.95
2017	$0.14	$0.47	$0.42	$0.06	$1.09
2018	$0.18	$0.46	$0.40	$0.06	$1.10
2019	$0.12	$0.46	$0.43	$0.04	$1.05
2020	$0.10	$0.46	$0.47	$0.03	$1.06
2021	$0.19	$0.49	$0.48	$0.07	$1.23
2022	$0.38	$0.46	$0.50	$0.12	$1.46

Market Procurement of Real-Time Ancillary Services

PJM uses market mechanisms to varying degrees in the procurement of ancillary services, including primary reserves, secondary reserves, and regulation. Ideally, all ancillary services would be procured taking full account of the interactions with the energy market. When a resource is used for an ancillary service instead of providing energy in real time, the cost of removing the resource, either fully or partially, from the energy market should be weighed against the benefit the ancillary service provides. The degree to which PJM markets account for these interactions depends on the timing of the product clearing and software limitations and the accuracy of unit parameters and offers.

The synchronized reserve market clearing is more integrated with the energy market clearing than the other ancillary services. Synchronized reserves are jointly cleared along with energy in every real-time market solution. Given the joint clearing of energy and flexible synchronized reserves, the synchronized reserve market clearing price should always cover the opportunity cost of providing flexible synchronized reserves. Inflexible synchronized reserves, provided by resources that require longer notice to take actions to prepare for reserve deployment, are not cleared along with energy in the real-time market solution. Inflexible synchronized reserves are cleared hourly by the Ancillary Service Optimizer (ASO) or the Day-Ahead Energy Market. The ASO uses forward looking information about the energy market, flexible synchronized reserves, and regulation to estimate the costs and benefits of using a resource for inflexible synchronized reserves.

Nonsynchronized reserves and offline secondary reserves are cleared with every real-time energy market solution. The energy commitment decisions for the offline resources have already been made when the RT SCED clears the reserves markets. Offline reserves have no lost opportunity cost.

Prices for the regulation and reserve markets are set by the pricing calculator (LPC), which uses the RT SCED solution as an input. The RT SCED partially, but not fully, clears the reserve market. The software determining the prices is not clearing the regulation market. Since the implementation of fast start pricing on September 1, 2021, the pricing calculations in LPC are not the same prices that result from the market clearing in RT SCED.

Recommendations

Regulation Market

- The MMU recommends that all data necessary to perform the regulation market three pivotal supplier test be saved by PJM so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the total regulation (TReg) signal sent on a fleet wide basis be eliminated and replaced with individual regulation signals for each unit. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that the ability to make dual offers (to make offers as both a RegA and a RegD resource in the same market hour) be removed from the regulation market. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the regulation market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the

19 Note: The totals in Table 10-6 account for after the fact billing adjustments made by PJM and may not match totals presented in past reports.
20 Reactive totals include FERC approved rates for reactive capability.

optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. FERC rejected.[21])

- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Not adopted.[22] FERC rejected.[23])
- The MMU recommends that the lost opportunity cost calculation used in the regulation market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[24])
- The MMU recommends that, to prevent gaming, there be a penalty enforced in the regulation market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour. (Priority: Medium. First reported 2016. Status: Not adopted. FERC rejected.[25])
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[26])
- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the regulation market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the $12.00 margin adder be eliminated from the definition of the cost based regulation offer because it is a markup and not a cost. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the ramp rate limited desired MW output be used in the regulation uplift calculation, to reflect the physical limits of the unit's ability to ramp and to eliminate overpayment for opportunity costs when the payment uses an unachievable MW. (Priority: Medium. First reported Q1, 2022. Status: Not adopted.)

Reserve Markets

- The MMU recommends that PJM replace the static MidAtlantic/Dominion Reserve Subzone with a reserve zone structure consistent with the actual deliverability of reserves based on current transmission constraints. (Priority: High. First reported 2019. Status: Partially adopted October 1, 2022.)
- The MMU recommends that the $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve because it is a markup and not a cost. (Priority: Medium. First reported 2018. Status: Adopted October 1, 2022.)
- The MMU recommends that the variable operating and maintenance cost be eliminated from the definition of the cost of tier 2 synchronized reserve and that the calculation of synchronized reserve variable operations and maintenance costs be removed from Manual 15. (Priority: Medium. First reported 2019. Status: Adopted October 1, 2022.)
- The MMU recommends that the components of the cost-based offers for providing regulation and synchronous condensing be defined in Schedule 2 of the Operating Agreement. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that the rule requiring that tier 1 synchronized reserve resources be paid the tier 2 price when the nonsynchronized reserve price is above zero be eliminated immediately and that, under the current rule, tier 1 synchronized reserve resources not be paid the tier 2 price when they do not respond. (Priority: High. First reported 2013. Status: Adopted October 1, 2022.)
- The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced on a daily and hourly basis. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer MW to 0 MW. (Priority: Medium. First reported 2013. Status: Adopted October 1, 2022.)

21 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
22 This recommendation was adopted by PJM for the energy market. Lost opportunity costs in the energy market are calculated using the schedule on which the unit was scheduled to run. In the regulation market, this recommendation has not been adopted, as the LOC continues to be calculated based on the lower of price or cost in the energy market offer.
23 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
24 *Id.*
25 *Id.*
26 *Id.*

- The MMU recommends that, for calculating the penalty for a synchronized reserve resource failing to meet its scheduled obligation during a spinning event, the penalty should be based on the actual time since the last spinning event of 10 minutes or longer during which the resource performed because performance is only measured for events 10 minutes or longer and that the tier 2 shortfall penalty should include LOC payments as well as SRMCP and MW of shortfall. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the use of Degree of Generator Performance (DGP) in the synchronized reserve market solution and improve the actual tier 1 estimate. If PJM continues to use DGP, DGP should be documented in PJM's manuals. (Priority: Medium. First reported 2018. Status: Adopted October 1, 2022.)
- The MMU recommends that the details of VACAR Reserve Sharing Agreement (VRSA) be made public, including any responsibilities assigned to PJM and including the amount of reserves that Dominion commits to meet its obligations under the VRSA. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that the VRSA be terminated and, if necessary, replaced by a reserve sharing agreement between PJM and VACAR South, similar to agreements between PJM and other bordering areas. (Priority: Medium. First reported 2020. Status: Adopted October 1, 2022.)
- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported 2015. Status: Adopted October 1, 2022.)
- The MMU recommends that PJM modify the DASR market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Status: Adopted October 1, 2022.)
- The MMU recommends that, in order to mitigate market power, offers in the DASR market be based on opportunity cost only. (Priority: Low. First reported 2009. Modified, 2018. Status: Adopted October 1, 2022.)

Frequency Response, Reactive, and Black Start

- The MMU recommends that all resources, new and existing, have a requirement to include and maintain equipment for primary frequency response capability as a condition of interconnection service. The PJM capacity and energy markets already compensate resources for frequency response capability and any marginal costs. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that new CRF rates for black start units, incorporating current tax code changes, be implemented immediately. The new CRF rates should apply to all black start units. The black start units should be required to commit to providing black start service for the life of the unit. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that separate cost of service payments for reactive capability be eliminated and the cost of reactive capability be recovered in the capacity market. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that payments for reactive capability, if continued, be based on the 0.95 power factor included in the voltage schedule in Interconnection Service Agreements. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if payments for reactive are continued, fleet wide cost of service rates used to compensate resources for reactive capability be eliminated and replaced with compensation based on unit specific costs. (Priority: Low. First reported 2019.[27] Status: Partially adopted.)
- The MMU recommends that Schedule 2 to OATT be revised to state explicitly that only generators that provide reactive capability to the transmission system that PJM operates and has responsibility for are eligible for reactive capability compensation. Specifically, such eligibility should be determined

27 The MMU has discussed this recommendation in state of the market reports since 2016 but Q3, 2019 was the first time it was reported as a formal MMU recommendation.

based on whether a generation facility's point of interconnection is on a transmission line that is a Monitored Transmission Facility as defined by PJM and is on a Reportable Transmission Facility as defined by PJM.[28] (Priority: Medium. First reported 2020. Status: Not adopted.)

Conclusion

The design of the PJM Regulation Market is significantly flawed.[29] The market design does not correctly incorporate the marginal rate of technical substitution (MRTS) in market clearing and settlement. The market design uses the marginal benefit factor (MBF) to incorrectly represent the MRTS and uses a mileage ratio instead of the MBF in settlement. The current market design allows regulation units that have the capability to provide both RegA and RegD MW to submit an offer for both signal types in the same market hour. However, the method of clearing the regulation market for an hour in which one or more units has a dual offer incorrectly accounts for the amount of RegD and the effective MW of the RegD that it clears. The result of the flaw is that the MBF in the clearing phase is incorrectly low compared to the MBF in the solution phase and the actual amount of effective MW procured is higher than the regulation requirement. This failure to correctly and consistently incorporate the MRTS into the regulation market design has resulted in both underpayment and overpayment of RegD resources and in the over procurement of RegD resources in all hours. The market results continue to include the incorrect definition of opportunity cost. These issues are the basis for the MMU's conclusion that the regulation market design is flawed.

To address these flaws, the MMU and PJM developed a joint proposal which was approved by the PJM Members Committee on July 27, 2017, and filed with FERC on October 17, 2017.[30] The PJM/MMU joint proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market. FERC rejected the joint proposal on March 30, 2018, as being noncompliant with Order No. 755.[31] The MMU and PJM separately filed requests for rehearing, which were denied by order issued March 26, 2020.[32]

The structure of the tier 2 synchronized reserve market was evaluated and the MMU concluded that the market was not structurally competitive. It was characterized by high levels of supplier concentration and inelastic demand. As a result, these markets were operated with market clearing prices and with offers based on the marginal cost of producing the product plus a margin. However, the $7.50 margin was not a cost. The margin was effectively a rule-based form of economic withholding and therefore not consistent with a competitive outcome. The variable operating and maintenance component of the synchronized reserve offer was not a cost of providing synchronized reserves and was also redundant with the costs included in the energy market offer. These elements of the offer were correctly eliminated on October 1, 2022.

The October 1, 2022, changes also include a synchronized reserve must offer requirement applicable to all generation capacity resources. This resulted in an increase in available supply. Combined with the removal of the $7.50 per MWh margin and the invalid variable operations and maintenance cost, supply and demand logic predicts lower prices, which occurred in October and November 2022. This is evidence of market efficiency. With the elimination of tier 1 reserves, the total reserve market clearing price credits, while based on lower prices, are paid to a larger MW quantity. Overall, the total credits at $2.3 million in October 2022 and $3.5 million in November 2022 were similar to historic months with similar energy prices.

The new reserve market design was tested during Winter Storm Elliott. The day-ahead reserve markets cleared ample reserves but those reserves were not available in real time as a result of forced outages and a maximum generation emergency. When they could not perform, suppliers were required to buy back their day-ahead reserve positions at shortage prices. As a result, customers received payment for reserves, which was not possible under the previous market design. Suppliers were charged and customers received $8.4 million in synchronized reserve credits and $23.8 million in nonsynchronized reserve credits for the month of December 2022. This market outcome is consistent with the reserves not being provided.

28 *See* PJM Transmission Facilities (note that this requires you first log into a PJM Tools account. If you do not, then the link sends you to an Access Request page, <https://pjm.com/markets-and-operations/ops-analysis/transmission-facilities>.

29 The current PJM regulation market design that incorporates two signals using two resource types was a result of FERC Order No. 755 and subsequent orders. Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).

30 18 CFR § 385.211.

31 162 FERC ¶ 61,295 (2018).

32 170 FERC ¶ 61,259 (2020).

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

The MMU concludes that the regulation market results were not competitive, and the market design is significantly flawed. The MMU concludes that the synchronized reserve market results were competitive. The MMU concludes that the secondary reserve market results were competitive.

Primary Reserve

NERC Performance Standard BAL-002-3, Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event, requires PJM to carry sufficient contingency reserve to recover from a sudden balancing contingency (usually a loss of generation). The Contingency Event Recovery Period is the time required to return the ACE to zero if it was zero or positive before the event or to its pre-event level if it was negative at the start of the event. The Contingency Reserve Restoration period is the time required to restore contingency (primary) reserves to a level greater than or equal to the largest single contingency after the end of the Contingency Event Recovery Period. NERC standards set the Contingency Event Recovery Period as 15 minutes and Contingency Reserve Restoration Period as 90 minutes.[33] The NERC requirement is 100 percent compliance and status must be reported quarterly. PJM implements this contingency reserve requirement using primary reserves.[34] PJM maintains 10 minute reserves (primary reserve) to ensure reliability in the event of disturbances. PJM's primary reserves are made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes. PJM does not have a Contingency Reserve Restoration Period standard.

33 See PJM. "PJM Manual 12: Balancing Operations," Rev. 47 (Oct. 1, 2022) Attachment D, "the Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. Subsequently, PJM must fully restore the Synchronized Reserve within 90 minutes." While this cited attachment only references restoring synchronized reserves, PJM Manuals 10 & 13 make it clear that primary reserves serve as PJM's contingency reserve.

34 See PJM. "PJM Manual 10: Pre-Scheduling Operations," § 3.1 Reserve Definitions, Rev. 42 (Oct. 1, 2021).

Market Structure

Demand

The NERC standard requires a control area to carry primary reserve MW equal to or greater than the largest single contingency (also known as the most severe single contingency, or MSSC).[35] PJM requires primary reserves in the amount of 150 percent of the largest single contingency with at least 100 percent of the requirement made up of synchronized reserves.[36] In 2022, the average synchronized reserve requirement was 1,711.7 MW in the MAD Subzone and 1,712.3 MW in the RTO Zone. The synchronized reserve requirement is calculated for every real-time market dispatch solution. PJM can make temporary adjustments to the primary reserve requirement when grid maintenance or outages change the largest contingency or in cases of hot weather alerts or cold weather alerts.

The minimum primary reserve market requirement is set equal to 150 percent of the largest single contingency for each market solution, ASO, IT SCED, and RT SCED. The largest single contingency is usually the output of the largest generating unit to which PJM adds 190 MW. In cases where temporary switching conditions create the risk that a single fault could remove several generators, PJM defines the largest single contingency as the sum of the output of those generators.[37]

PJM can also increase the primary and synchronized reserve requirement in cases of hot weather or cold weather alerts or escalating emergency procedures.[38] In 2022, the average primary reserve requirement for the RTO Zone was 2,473.4 MW. The average primary reserve requirement in the MAD Subzone was 2,472.5 MW.

The MMU identified instances when PJM increased the primary and synchronized reserve requirements (Table 10-7).

35 NERC BAL-002-3. "Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event," September 25, 2018. <https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-3.pdf>.

36 See PJM. "PJM Manual 13: Emergency Operations," § 2.2 Reserve Requirements, Rev. 85 (Oct. 1, 2022).

37 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3 Reserve Requirement Determination, Rev. 122 (Oct. 1, 2022).

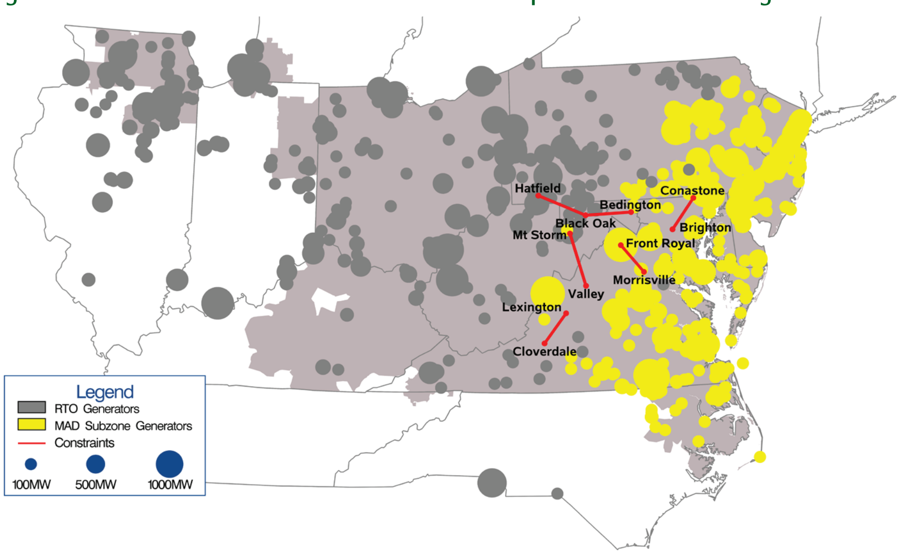
38 See *id.*

Table 10-7 Temporary adjustments to primary and synchronized reserve: January through December, 2022

From	To	Number of Hours	Amount of Adjustment
1-Jan-22	9-Feb-22	936	Primary Reserve (64 MW), Synchronized Reserve (43 MW)
21-Feb-22	25-Feb-22	103	Primary Reserve (0 MW), Synchronized Reserve (0 MW)
29-Mar-22	31-Mar-22	54	Primary Reserve (0 MW), Synchronized Reserve (0 MW)
10-Apr-22	15-Apr-22	122	Primary Reserve (0 MW), Synchronized Reserve (0 MW)
16-May-22	20-Jun-22	848	Primary Reserve (39 MW), Synchronized Reserve (26 MW)
28-Jun-22	30-Jun-22	42	Primary Reserve (1,192 MW), Synchronized Reserve (794 MW)
26-Jul-22	26-Jul-22	1	Primary Reserve (76 MW), Synchronized Reserve (50 MW)
6-Sep-22	10-Sep-22	96	Primary Reserve (139 MW), Synchronized Reserve (92 MW)
10-Oct-22	12-Oct-22	43	Primary Reserve (1,081 MW), Synchronized Reserve (721 MW)
1-Nov-22	4-Nov-22	78	Primary Reserve (55 MW), Synchronized Reserve (37 MW)
7-Nov-22	2-Feb-23	2091	Primary Reserve (135 MW), Synchronized Reserve (90 MW)

Transmission constraints can limit the deliverability of reserves within the RTO, requiring the definition of a subzone. In 2022, PJM defined a single subzone, the Mid-Atlantic Dominion (MAD) Subzone (Figure 10-1).[39] Figure 10-1 is a map of constraints and major generation sources. The constraints separating the RTO Zone and MAD Subzone are defined by underlying grid topology. The RTO Zone into MAD Subzone constraints reflect limits on the transmission line capacity that separate the RTO Zone and MAD Subzone. If, in the case of a spinning event, the current economic dispatch plus the current synchronized market dispatch would overload the constraint, then all additional synchronized reserve MW must be cleared from the unconstrained side of the constraints. When this occurs, the synchronized reserve prices between the RTO Zone and the MAD Subzone will diverge. In practice, PJM has always maintained only the MAD Subzone and in every market solution the most limiting constraining path sets the transfer limit between the RTO and MAD Subzone. PJM can also define a new subzone, if needed, but only one subzone can be active at any time.

Figure 10-1 PJM RTO Zone and MAD Subzone map of constraints and generation sources



39 Additional subzones may be defined by PJM to meet system reliability needs. PJM will notify stakeholders in such an event. See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3.2 Creation of New Reserve Subzones, Rev. 122 (Oct. 1, 2022).

The most limiting transmission constraint for power flow from the RTO Zone into the MAD Subzone since August 2017 has been the AP South Interface. The most frequent constraint in 2022 was Bedington-Black Oak, then Brighton-Conastone, and Cloverdale-Lexington.

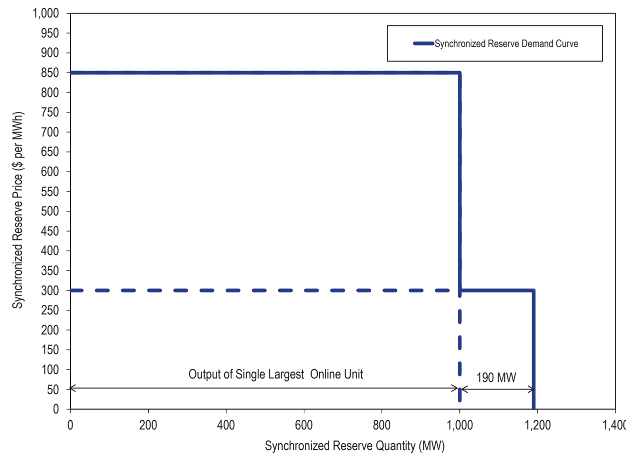
The choice of MAD was a result of historical congestion patterns where limits to transmission capacity to deliver power from outside the MAD Subzone into the MAD Subzone necessitated maintaining reserves in the MAD area to respond to disturbances within the subzone. On most days, the MAD Subzone is no longer relevant. PJM may need to maintain or operate resources in other local areas to maintain local reliability. Currently, these units are committed out of market for reliability reasons. The value of operating these resources, including generators that are manually committed for reliability is not correctly reflected in prices. A more efficient way to reflect these requirements would be to have locational reserve requirements that are adjusted based on PJM forecasts and reliability studies. As of October 1, 2022, PJM has a process to revise the definition of the subzone. The subzone definition may change as often as daily based on system conditions.[40] In the last three months of 2022, PJM did not change the subzone.

Operating Reserve Demand Curves

PJM's administratively defined demand curves for reserves are called Operating Reserve Demand Curves. The first step of the demand curves for primary, synchronized reserves, and 30 minute reserves are set at the minimum reserve requirement for each product. Since the primary and synchronized minimum reserve requirements are based on the actual output of the largest resource, the MW value of the first step changes in real time based on the real-time dispatch solution. The first step is priced at $850 per MWh. The second step of the primary, synchronized, and 30 minute reserve demand curves extends the reserve requirements. The extended reserve requirements are defined as the primary and synchronized reserve requirements, plus 190 MW. This 190 MW second step is priced at $300 per MWh. Figure 10-2 shows an example of the updated synchronized reserve demand curve when the output of the single largest unit in the region is 1,000 MW.

The current operating reserve demand curves (ORDC) in PJM define an administrative price for estimated reserves up to the extended reserve requirement quantities. The demand curve shown in Figure 10-2 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 10-2 Real-time synchronized reserve demand curve showing the permanent second step



Supply

In the first nine months of 2022, the demand for primary reserve was satisfied by tier 1 synchronized reserves, tier 2 synchronized reserves and nonsynchronized reserves. For the last three months of 2022, the demand for primary reserve was satisfied by synchronized reserves and nonsynchronized reserves. After the synchronized reserve requirement is satisfied, the remainder of primary reserves is from the least expensive combination of synchronized and nonsynchronized reserves.

Estimated tier 1 contributed to meeting PJM's primary reserve requirement and PJM's synchronized reserve requirement. In the MAD Subzone, an average of 693.6 MW of tier 1 was available in the first nine months 2022 (Table 10-8). Tier 1 synchronized reserve fully satisfied the MAD Subzone synchronized reserve requirement or reduced the need for tier 2 synchronized reserve to self-scheduled reserves in 4.6 percent of dispatch solutions in the first nine months of 2022. In the RTO Zone, an average of 1,531.4 MW of tier 1 was available, fully satisfying the synchronized reserve requirement in 36.0 percent of real-time dispatch solutions (Table 10-9) in the first nine months of 2022.

40 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3.2 Creation of New Reserve Subzones, Rev. 122 (Oct. 1, 2022).

In the first nine months of 2022, all nonemergency generation capacity resources, regardless of online/offline state, were required to submit a daily offer for tier 2 synchronized reserve in Markets Gateway prior to the offer submission deadline (14:15 the day prior to the operating day). Resources listed as available for tier 2 synchronized reserve without a synchronized reserve offer had their offer price automatically set to $0.00. Offer MW and other non-cost offer parameters could be changed during the operating day. Owners who opted in for intraday updates could change their offer price up to 65 minutes before the hour. Certain unit types, including nuclear, wind, solar, and energy storage resources, were expected to offer zero MW.[41]

The previous synchronized reserve must offer requirement allowed resources to withhold reserves by setting their own offer as low as zero MW. Under the new must offer requirement, PJM calculates offers for resources based on their energy market offers. If resources self schedule their energy output such that they effectively withhold reserves, they are in violation of the must offer requirement. Resource types that are not dispatched economically by PJM submit their offer MW for reserves. The largest class of such resources is hydro resources with controllable output. Like all other resources, hydro resources are required to offer their full reserve capability to PJM at all times.

In the first nine months of 2022, offer prices for synchronized reserve were capped at $7.50 per MWh plus operation and maintenance cost, as defined in PJM Manual 15. Consistent with the MMU's recommendations, both the $7.50 per MWh adder and the incorrect variable operations and maintenance cost in Manual 15 were removed as of October 1, 2022.

In the clearing process, after tier 1 was estimated, the remainder of the synchronized reserve requirement was met by tier 2.

In the first nine months of 2022, in the MAD Subzone, there was an average of 1,289.8 MW of eligible nonsynchronized reserve supply available to meet the average demand for primary reserve (Table 10-8). In the RTO Zone, an average of 1,633.2 MW of nonsynchronized reserve supply was available to meet the average demand of 2,436.9 MW (Table 10-9).

41 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2 PJM Synchronized Reserve Market Business Rules, Rev. 121 (July 7, 2022).

Table 10-8 provides the average dispatch solution reserves, by type of reserve, used by the RT SCED market solution to satisfy the primary reserve requirement in the MAD Subzone in 2022. In the last three months of 2022, all synchronized reserves received the market clearing price and had a performance obligation, so all synchronized reserves for those months are included in the column "Scheduled Synchronized Reserve MW." For the first nine months of 2022, this column includes only the tier 2 synchronized reserve, as tier 1 was estimated, not scheduled.

Table 10-8 Average monthly reserves used to satisfy the primary reserve requirement, MAD Subzone: January 2021 through December 2022

Year	Month	Tier 1 Total MW	Scheduled Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2021	Jan	837.0	880.1	1,294.1	3,011.1
2021	Feb	976.6	762.0	1,206.8	2,945.4
2021	Mar	884.1	854.3	1,067.9	2,806.3
2021	Apr	687.0	913.5	1,072.0	2,672.5
2021	May	652.2	1,041.9	983.1	2,677.2
2021	Jun	833.7	896.8	1,167.4	2,897.9
2021	Jul	890.4	829.2	1,196.9	2,916.5
2021	Aug	914.0	846.3	1,232.3	2,992.6
2021	Sep	906.4	814.0	1,153.9	2,874.2
2021	Oct	592.9	1,162.4	902.5	2,657.8
2021	Nov	569.2	1,166.4	1,067.3	2,802.9
2021	Dec	742.3	981.3	1,216.4	2,940.0
2021	Average	789.4	930.2	1,129.6	2,849.2
2022	Jan	849.0	818.0	1,344.4	3,011.4
2022	Feb	898.3	810.3	1,277.2	2,985.8
2022	Mar	700.2	990.6	1,097.0	2,787.9
2022	Apr	567.6	1,009.3	1,190.0	2,767.0
2022	May	594.9	1,124.1	1,109.9	2,829.0
2022	Jun	654.5	1,130.7	1,288.4	3,073.6
2022	Jul	601.7	1,121.2	1,150.0	2,872.9
2022	Aug	631.1	1,110.9	1,236.6	2,978.6
2022	Sep	761.6	856.9	967.2	2,585.7
2022	Oct	NA	1,830.8	810.1	2,640.9
2022	Nov	NA	1,819.5	857.5	2,677.0
2022	Dec	NA	1,896.2	822.8	2,719.1
2022	Average	695.4	1,213.3	1,094.6	2,826.6

Table 10-9 shows the average dispatch solution reserves, by type of reserve, satisfying the primary reserve requirement in the RTO Zone in January 2021 through December 2022.

Table 10-9 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: January 2021 through December 2022

Year	Month	Tier 1 Total MW	Scheduled Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2021	Jan	1,757.3	333.7	1,448.8	3,539.8
2021	Feb	1,847.8	461.2	1,289.4	3,598.4
2021	Mar	1,701.9	434.1	1,269.9	3,406.0
2021	Apr	1,308.0	549.6	1,121.5	2,979.2
2021	May	1,376.5	591.6	1,094.8	3,062.9
2021	Jun	1,694.2	468.7	1,242.4	3,405.3
2021	Jul	1,676.2	483.4	1,259.8	3,419.3
2021	Aug	1,765.3	500.3	1,268.9	3,534.5
2021	Sep	1,777.5	432.5	1,456.0	3,666.0
2021	Oct	1,109.3	779.6	1,160.1	3,048.9
2021	Nov	1,159.9	747.0	1,437.0	3,343.8
2021	Dec	1,622.7	441.3	1,843.5	3,907.5
2021	Average	1,564.9	518.8	1,324.8	3,408.4
2022	Jan	1,711.1	358.8	1,900.9	3,970.8
2022	Feb	1,949.3	256.6	1,863.6	4,069.4
2022	Mar	1,513.4	448.2	1,996.8	3,958.4
2022	Apr	1,152.3	596.2	1,694.9	3,443.4
2022	May	1,471.1	606.4	1,822.1	3,899.6
2022	Jun	1,532.6	654.4	2,099.1	4,286.1
2022	Jul	1,464.7	592.0	1,988.3	4,045.0
2022	Aug	1,428.9	657.7	2,083.9	4,170.5
2022	Sep	1,589.2	450.8	1,847.5	3,887.5
2022	Oct	NA	1,831.7	955.5	2,787.2
2022	Nov	NA	1,822.0	1,011.5	2,833.6
2022	Dec	NA	1,900.0	964.8	2,864.8
2022	Average	1,534.7	852.6	1,684.4	3,682.2

Market Clearing

The market solution software for reserves consists of: the Ancillary Services Optimizer (ASO) solving hourly; the intermediate term security constrained economic dispatch market solution (IT SCED); and the real-time (short term) security constrained economic dispatch market solution (RT SCED).

Inflexible synchronized reserve is committed by the ASO. This includes demand response and condensers. In the first nine months of 2022, if there was enough estimated tier 1 MW available to satisfy the synchronized reserve requirement, then no inflexible tier 2 synchronized reserve MW was committed. If the sum of the tier 1 MW and the ASO-committed inflexible tier 2 MW did not meet the synchronized reserve requirement, then the RT SCED would commit available flexible tier 2 synchronized reserve. In the last three months of 2022, available flexible synchronized reserves cleared economically in every case. The clearing price equaled zero if reserves that were previously categorized as tier 1 fully satisfied the requirement. The primary reserve requirement is met by economically assigning inflexible synchronized reserves, flexible synchronized reserves, and nonsynchronized reserves.

Figure 10-3 shows how the daily average market solutions satisfy the primary reserve requirement for the RTO Zone. PJM temporarily increased the primary and synchronized reserve requirements in June. The details are in Table 10-7. From December 23 through December 25, during Elliott, PJM generators experienced numerous outages, resulting in multiple shortages of primary reserve and synchronized reserve during this period. As Figure 10-3 is a plot of daily averages, it does not fully capture the severity of the shortfall, which at times exceeded 1,000 MW. The shortfalls are better seen in Figure 10-4 which shows the amount of reserves cleared by RT SCED in each approved five minute market solution. However, as many of the reserve MW cleared were unavailable due to outages and generators failing to start, the true amounts of reserve MW are lower than depicted.

Figure 10-3 RTO reserve zone primary reserve MW by source (Daily Averages): January through December, 2022

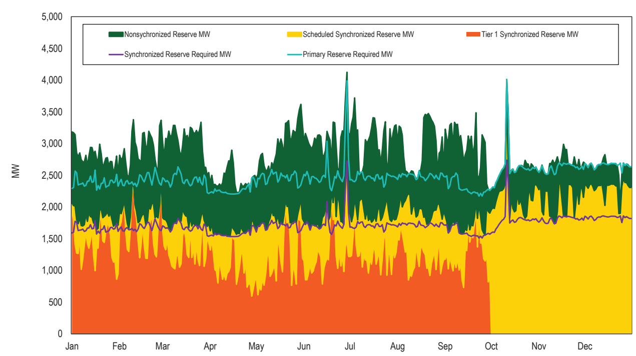
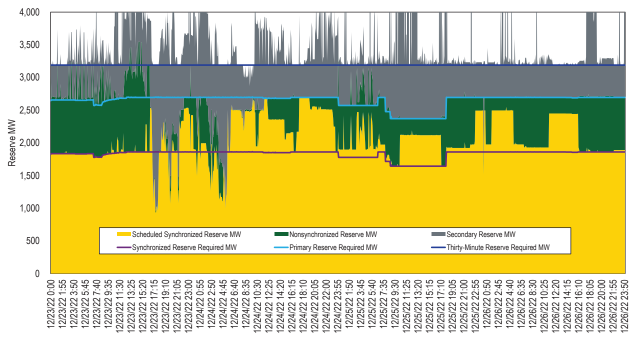


Figure 10-4 Reserves cleared by RT SCED: December 23 through December 26, 2022



In the first nine months of 2022, tier 1 synchronized reserve was the primary source of synchronized reserves, but tier 1 and tier 2 were both needed to meet the synchronized reserve requirement. In the last three months of 2022, the single synchronized reserve product was the primary source of primary reserve. As seen in Figure 10-3 and Figure 10-4, since the October 1 changes, the character of PJM's real-time reserves has shifted from an excess in nonsynchronized reserve satisfying the primary reserve requirement to an excess in the newly introduced secondary reserve satisfying the thirty-minute reserve requirement.

Market Concentration

For both the day-ahead and real-time markets, The RTO primary reserve market was moderately concentrated, and the MAD primary reserve market was highly concentrated in the last three months of 2022. Table 10-10 shows the average HHI for primary reserves in the last three months of 2022.

Table 10-10 Average primary reserve HHI: October through December, 2022

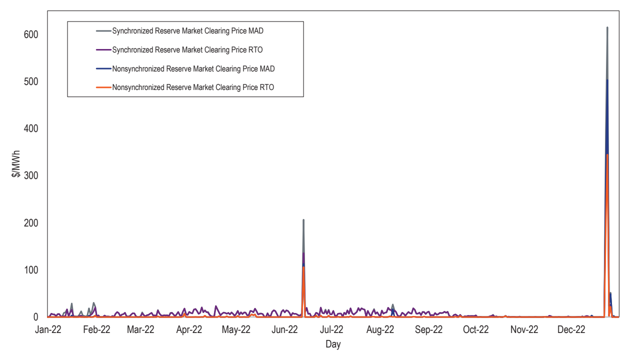
Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%
RTO	RT	1123	59.8%
RTO	DA	1168	55.4%
MAD	RT	3213	99.6%
MAD	DA	2102	96.9%

Prices

Figure 10-5 shows daily weighted average synchronized and nonsynchronized market clearing prices in 2022. The MAD SRMCP and RTO SRMCP prices diverged in 1,479 five-minute intervals, 0.7 percent of the total 210,216 intervals in 2022.

There was a significant increase in the price of reserves on June 13, 2022, as a result of shortage pricing (Figure 10-5). On June 13, the RTO primary reserve was short for 35 intervals and the RTO synchronized reserve was short for 11 intervals, all concurrent with the primary reserve shortage. The MAD primary reserve was short for 35 intervals and the MAD synchronized reserve was short for eight intervals, all concurrent with the primary reserve shortage. Prices were lower in October and November 2022, after the implementation of the must offer requirement for synchronized reserves. From December 23, 2022, through December 25, 2022, due to Elliott and numerous outages, PJM was short of primary reserve and synchronized reserve for 203 intervals. Meanwhile, there were multiple spinning events during this period, including two that lasted over an hour.

Figure 10-5 Daily average market clearing prices ($/MWh) for synchronized reserve and nonsynchronized reserve: January through December, 2022



Tier 1 Synchronized Reserve

In the first nine months of 2022, tier 1 synchronized reserve was a component of primary reserve comprised of online resources following economic dispatch and able to ramp up from their current output in response to a synchronized reserve event. Effective Post October 1, tier 1 and tier 2 synchronized reserve have been consolidated into a single synchronized reserve product, and all synchronized reserve is cleared via market mechanisms. As a result, the values reported for tier 1 are only for the first nine months of 2022.

The tier 1 synchronized reserve for a unit was estimated as the lesser of the available 10 minute ramp or the difference between the economic dispatch point and the synchronized reserve maximum output, which by default is equal to its economic maximum. Resource owners may request a lower synchronized reserve maximum if a physical limitation exists.[42] Tier 1 resources were identified by the market solution. Tier 1 synchronized reserves had an incremental cost of zero. Tier 1 synchronized reserves were paid under two circumstances. Tier 1 reserves were paid when they responded to a synchronized reserve event. Tier 1 reserves were paid the synchronized reserve market clearing price when the nonsynchronized reserve market clearing price was above $0.

While PJM relied on tier 1 resources to respond to a synchronized reserve event, tier 1 resources were not obligated to respond during an event. Tier 1 resources were credited if they responded but were not penalized if they did not.

Market Structure

Supply

All generating resources operating on the PJM system with the exception of those assigned to tier 2 synchronized reserve were available for tier 1 synchronized reserve and any response to a spinning event would be credited at the synchronized energy premium price, except during intervals in which the non-synchronized reserve market clearing price was above $0, in which case response was credited at the synchronized reserve market clearing price.

Introduced in 2014, DGP (Degree of Generator Performance) was a metric to improve the accuracy of the tier 1 MW estimate used by the market solution. In the first nine months of 2022, the available tier 1 MW estimated by the market solution for each resource was based upon its economic dispatch, and submitted synchronized reserve ramp rate, adjusted by its DGP. PJM communicated to generation operators whose tier 1 MW was part of the market solution the latest estimate of units' tier 1 MW and units' current DGP.[43] DGP violated the basic PJM principle that generation owners are solely responsible for their own offers. In addition, DGP was a crude estimate of ramp rates and did not account for the actual discontinuities along unit offer curves. The MMU's recommendation to remove the use of DGP was adopted effective October 1, 2022.

42 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2.1 Communication for Reserve Capability Limitation, Rev. 122 (Oct. 1, 2022).

43 PJM. Ancillary Services, "Communication of Synchronized Reserve Quantities to Resource Owners," (May 6, 2015). <http://www.pjm.com/~/media/markets-ops/ancillary/communication-of-synchronized-reserve-quantities-to-resource-owners.ashx>

The supply of tier 1 synchronized reserve available to the market solution was adjusted by eliminating tier 1 MW from unit types that could reliably provide synchronized reserve. These unit types are nuclear, wind, solar, landfill gas, energy storage, and hydro units.[44] These unit types were credited the synchronized energy premium price, like any other responding unit, if they responded to a spinning event, but were not, however, paid as tier 1 resources when the nonsynchronized reserve market clearing price was above $0 outside of spinning events. There was a review process for resources excluded by default from the tier 1 estimate that request to be included.[45] PJM also excluded units, regardless of type, that it deemed unreliable as tier 1, though it allowed those resources to provide tier 2 synchronized reserve.

Table 10-11 provides tier 1 synchronized reserve supplied by resource and fuel type in the first nine months of 2022, including all tier 1 credited for responding to synchronized reserve events and paid when the nonsynchronized reserve price exceeded $0 per MW.

Table 10-11 Supply of tier 1 synchronized reserve by resource and fuel type: January through September, 2022

Unit/Fuel Type	Percent by MW	Percent by Credits
Combined Cycle	46.3%	44.4%
Steam - Coal	19.5%	24.5%
CT - Natural Gas	12.8%	10.6%
Solar	9.9%	8.3%
Wind	5.4%	5.8%
Steam - Natural Gas	2.6%	2.6%
Hydro - Run of River	1.4%	1.8%
Steam - Other	1.3%	0.8%
RICE - Natural Gas	0.4%	0.4%
CT - Oil	0.1%	0.2%
Hydro - Pumped Storage	0.1%	0.2%
DSR	0.1%	0.2%
Nuclear	0.1%	0.2%
RICE - Other	0.0%	0.0%
Steam - Oil	0.0%	0.0%
Battery	0.0%	0.0%
CT - Other	0.0%	0.0%
RICE - Oil	0.0%	0.0%

In the first nine months of 2022, the SCED market solutions estimated that tier 1 MW from an average of 60 units could have an average of 1,531.4 MW of ramp available in a spinning event. For the 14 spinning events in the first nine months of 2022, PJM paid a total of 3,734.0 MW of tier 1 response across 37 intervals. Settlements included units like wind, solar, nuclear, and

44 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 121 (July 7, 2022).

45 See *id.*

demand response which were not a part of the estimated tier 1 in the SCED market solutions.

The actual response was the sum of the products contributing to total ACE increase from the time the event is initiated to 10 minutes after the event is initiated. Total increase in ACE was a sum not only of tier 1 response, but also of tier 2 response, RegA and RegD actual response (RegD response is sometimes a MW increase and sometimes a MW decrease), and changes to net imports/exports across PJM's boundaries (sometimes an increase and sometimes a decrease in MW).

In the RTO Reserve Zone, the average estimated tier 1 synchronized reserve was 1,531.4 MW (Table 10-9). In 36.0 percent of dispatch solutions, the estimated tier 1 synchronized reserve was greater than the synchronized reserve requirement, meaning that the synchronized reserve requirement was met entirely by tier 1 synchronized reserve plus self-scheduled tier 2.

In the first nine months of 2022, the average estimated tier 1 synchronized reserve within the MAD Subzone was 693.6 MW (Table 10-8). In 4.6 percent of dispatch solutions the estimated tier 1 synchronized reserve available within the MAD Subzone plus the self-scheduled tier 2 in MAD was greater than the synchronized reserve requirement and no tier 2 market needed to be cleared.

Demand

There was no required amount of tier 1 synchronized reserve. The estimated tier 1 MW contributed to meeting the demand for synchronized and primary reserve.

The ancillary services market solution treated the cost of estimated tier 1 synchronized reserve as $0, even when the cost of tier 1 was positive because the nonsynchronized reserve market clearing price was above $0. As a result, the optimization could not and did not minimize the total cost of primary reserves. The MMU recommended that tier 1 synchronized reserve not be paid when the nonsynchronized reserve market clearing price is above $0. This recommendation was adopted effective October 1, 2022.

Supply and Demand

When solving for the synchronized reserve requirement the market solution first estimated the amount of tier 1 available from the energy dispatch. If the requirement was not filled by tier 1, it then committed tier 2 beginning with all self-scheduled synchronized reserve.

In the MAD Subzone, the market solution took all tier 1 MW estimated to be available within the MAD Subzone as well as the synchronized reserve MW estimated to be available within the MAD Subzone from the RTO Zone. If the total tier 1 synchronized reserve was less than the synchronized reserve requirement, the remainder of the synchronized reserve requirement was filled with tier 2 synchronized reserve.

Tier 1 Synchronized Reserve Payments

Tier 1 synchronized reserve was awarded credits under two circumstances. The first was in response to a spinning event. The second was during intervals outside of a spinning event during which the non-synchronized reserve market clearing price was above $0 and the unit was included in the estimated tier 1 MW.

In response to a spinning event, all resources (except scheduled tier 2 resources) were paid for increasing output (or reducing load for demand response) at the rate of $50 per MWh in addition to LMP during intervals in which the non-synchronized reserve market clearing price was $0.[46] This was the synchronized energy premium price. Spinning event response is calculated as the highest output between 9 minutes and 11 minutes after the event is declared minus the lowest output between one minute before and one minute after the event is declared. Generator outputs are measured and reported to PJM every four seconds via SCADA. Total response credited to a resource was capped at 110 percent of estimated capability. As a result, spinning event response involved more MW response than the original estimate of tier 1. Many resources that were not included in PJM's estimate of tier 1 nevertheless responded to spinning events and in accordance with the PJM Tariff were paid the synchronized energy premium price. This included incidental response from nuclear units or steam turbines running at maximum output. Tier 1 synchronized reserve that was part of the estimate when there was no spinning event was also credited for its full estimated MW whenever the nonsynchronized reserve market clearing price was above $0.

In the event that the nonsynchronized reserve market clearing price was above $0 and there was a spinning

46 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements, Rev. 121 (July 7, 2022).

event, estimated tier 1 was credited with the lesser of its actual response or its estimated capability times the SRMCP. Tier 1 synchronized reserve not part of the estimate was credited the SRMCP times its actual response.[47] In the first nine months of 2022, the nonsynchronized reserve market clearing price was above $0 in 609 five-minute intervals (0.8 percent of the total 78,612).

In the first nine months of 2022, tier 1 synchronized reserve spinning event response credits of $246,309 were paid for 14 spinning events averaging 10.1 minutes. Table 10-12 shows the number of spinning events each month, the credits paid for tier 1 response, the number of MWh credited, and the actual response in MW.

Table 10-12 Tier 1 synchronized reserve event response credits: January 2021 through September 2022

Year	Month	Number of Spinning Events	Total Tier 1 Spinning Event Credits	Total Tier 1 Spinning Event Credited (MWh)	Total Tier 1 Spinning Response from Event Start to Event End (MW)
2021	Jan	1	$6,796	135.9	1,165.0
2021	Feb	0	NA	NA	NA
2021	Mar	1	$15,729	314.6	1,715.8
2021	Apr	2	$40,442	808.8	4,677.8
2021	May	1	$21,822	436.4	2,618.6
2021	Jun	2	$16,275	325.5	3,183.2
2021	Jul	2	$16,026	320.5	2,999.1
2021	Aug	2	$46,487	929.7	4,666.3
2021	Sep	1	$126,863	279.2	2,094.2
2021	Oct	2	$27,267	545.3	3,800.4
2021	Nov	3	$50,939	1,018.8	6,024.5
2021	Dec	1	$7,188	143.8	1,232.3
2021	Total	18	$375,832	5,258.6	34,177.2
2022	Jan	1	$9,160	183.2	1,221.3
2022	Feb	0	NA	NA	NA
2022	Mar	1	$10,600	212.0	1,817.1
2022	Apr	3	$82,685	1,653.7	6,277.2
2022	May	4	$76,641	1,532.8	8,854.1
2022	Jun	2	$26,620	532.4	3,982.1
2022	Jul	1	$14,594	291.9	2,189.1
2022	Aug	0	NA	NA	NA
2022	Sep	2	$26,010	520.2	5,202.0
2022	Total	14	$246,309	4,926.2	29,542.9

Paying Tier 1 the Tier 2 Price

Tier 1 synchronized reserve had zero marginal cost and the corresponding competitive price for tier 1 synchronized reserves was also zero. However, the PJM rules artificially created a marginal cost of tier 1 when the price of nonsynchronized reserve was greater than zero and tier 1 was paid the tier 2 price. The PJM market solutions did not include that marginal cost and therefore did not solve for the efficient level of tier 1, tier 2 and nonsynchronized reserve in those cases. When called to respond to a spinning event, tier 1 was compensated at the synchronized energy premium price (Table 10-15). However, the shortage pricing tariff changes (October 1, 2012) modified the pricing of tier 1 so that tier 1 synchronized reserve was paid the tier 2 synchronized reserve market clearing price whenever the nonsynchronized reserve market clearing price rose above zero. The rationale for this change was and is unclear, but it had a significant impact on the cost of tier 1 synchronized reserves (Table 10-13). In the first nine months of 2022, the nonsynchronized reserve market clearing price was above $0.00 in 0.8 percent of all intervals, or 609 of the total 78,612. This is a decrease from the first nine months of 2021, in which 2.1 percent of intervals had a market clearing price above $0.00, or 1,631 of the total 78,601. For those intervals, estimated tier 1 synchronized reserve was paid $6,178,605 for an average of 588.5 MW per interval of which all credits were for intervals outside of spinning events.

47 See PJM. "PJM Manual 28: Operating Agreement Accounting," § 6.2.1 Synchronized Reserve Clearing Price Credit, Rev. 87 (Jul. 27, 2022).

Table 10-13 Price of tier 1 synchronized reserve attributable to a nonsynchronized reserve price above zero: January 2021 through September 2022

Year	Month	Number of Intervals When NSRMCP > $0	Weighted Average SRMCP When NSRMCP > $0	Total Tier 1 MWh When NSRMCP > $0	Total Tier 1 Credits When NSRMCP > $0	Average Tier 1 MWh Monthly When NSRMCP > $0
2021	Jan	31	$36.20	3,625.7	$75,337	604.3
2021	Feb	160	$20.31	19,953.0	$326,372	739.0
2021	Mar	60	$95.30	7,775.0	$724,173	518.3
2021	Apr	196	$10.34	24,978.1	$203,281	531.4
2021	May	644	$12.75	74,895.9	$797,736	720.2
2021	Jun	199	$12.62	25,628.0	$255,053	596.0
2021	Jul	95	$27.79	13,751.7	$325,970	528.9
2021	Aug	123	$56.79	15,098.7	$758,395	503.3
2021	Sep	123	$26.95	18,665.3	$454,768	777.7
2021	Oct	865	$20.82	113,069.8	$1,828,570	796.3
2021	Nov	490	$33.16	54,585.5	$1,527,555	941.1
2021	Dec	22	$69.35	2,487.4	$87,728	414.6
2021	Total	3,008	$32.10	374,514.1	$7,364,937	639.3
2022	Jan	17	$147.27	2,039.3	$200,464	407.9
2022	Feb	0	NA	NA	NA	NA
2022	Mar	30	$116.28	3,696.5	$329,826	528.1
2022	Apr	56	$51.67	6,702.1	$247,448	515.5
2022	May	240	$33.95	29,644.6	$767,809	871.9
2022	Jun	120	$372.44	11,604.3	$4,062,541	828.9
2022	Jul	29	$47.00	3,581.9	$141,084	398.0
2022	Aug	81	$37.43	8,622.6	$272,513	538.9
2022	Sep	36	$37.48	5,570.0	$156,920	618.9
2022	Total	609	$105.44	71,461.3	$6,178,605	588.5

The additional payments to tier 1 synchronized reserves under the shortage pricing rule were a windfall. Table 10-14 shows the amount of windfall paid to tier 1 resources from January 2014 through September 2022.

Table 10-14 Windfall payments made to tier 1 resources: January 2014 through September 2022

Year	Windfall Payment
2014	$89,719,045
2015	$34,397,441
2016	$4,948,084
2017	$2,197,514
2018	$4,732,025
2019	$3,217,178
2020	$3,320,726
2021	$7,354,224
2022 (Jan-Sep)	$6,178,605
Total	$156,064,842

The additional payment did not create an incentive to provide more tier 1 synchronized reserves. The additional payment was not a payment for performance; all estimated tier 1 received the higher payment regardless of whether they provided any response during any spinning event. Tier 1 resources were not obligated to respond to synchronized reserve events. In the first nine months of 2022, there were three spinning events of 10 minutes or longer. In those events, an average of 70.9 percent of the estimated tier 1 responded and 51.4 percent of tier 2 responded.

Tier 1 should have been compensated only for a response to synchronized reserve events, as it was before the 2012 shortage pricing changes. This compensation required that when a synchronized reserve event was called, all tier 1 response was paid the synchronized energy premium price. This recommendation was adopted effective October 1, 2022.

PJM's tier 1 compensation rules prior to the October 1 changes are presented in Table 10-15.

Table 10-15 Tier 1 compensation as implemented by PJM

Tier 1 Compensation by Type of Interval as Currently Implemented by PJM		
Interval Parameters	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWi
NSRMCP>$0	T1 credits = T2 SRMCP * estimated tier 1 MW	T1 credits = T2 SRMCP * min(estimated tier 1 MW, actual response MWi)

The MMU's recommended compensation rules for tier 1 MW prior to the October 1 changes are in Table 10-16.

Table 10-16 Tier 1 compensation as recommended by MMU

Tier 1 Compensation by Type of Hour as Currently Recommended by MMU		
Interval Parameters	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWi
NSRMCP>$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWi

Tier 2 Synchronized Reserve Market

Synchronized reserve is provided by generators or demand response resources synchronized to the grid and capable of increasing output or decreasing load within 10 minutes. In the first nine months of 2022, synchronized reserve consisted of tier 1 and tier 2 synchronized reserves. When the synchronized reserve requirement could not be met by tier 1 synchronized reserve, PJM cleared a market to satisfy the requirement with tier 2 synchronized reserve. Tier 2 synchronized reserve was provided by online resources, either synchronized to the grid but not producing energy, or dispatched to provide synchronized reserve at an operating point below their economic dispatch point. Tier 2 synchronized reserve was also provided by demand resources that offered to reduce load in the event of a synchronized reserve event. Tier 2 synchronized reserves were committed to be available in the event of a synchronized reserve event. Tier 2 resources had a must offer requirement. Some tier 2 resources were scheduled by the ASO 60 minutes before the operating hour and committed to provide synchronized reserve for the entire hour. Tier 2 resources were paid the higher of the SRMCP or their offer price plus lost opportunity cost (LOC). Demand response resources were paid the clearing price (SRMCP).

Synchronized reserve resources can be flexible or inflexible. Inflexible resources are defined as those resources that require an hourly commitment due to minimum run times or staffing constraints. Examples of inflexible reserves are synchronous condensers operating in condensing mode, resources with an economic minimum (EcoMin) equal to economic maximum (EcoMax), offline CTs and hydro that can operate in the condense mode, and demand resources. Inflexible synchronized reserve resources are committed for a full hour by the hour ahead ASO market solution. Inflexible resources require a 30 minute notification time and cannot be released for energy during the operating hour. The inflexible commitments made by the hour ahead ASO solution may satisfy only part of the synchronized reserve requirement. The actual requirement is determined by the RT SCED solution and the requirement not satisfied by inflexible units is satisfied by flexible units. Flexible resources are already online for energy, require no notification time, and can be automatically dispatched.

Market Structure

Supply

In the first nine months of 2022, PJM had a must offer tier 2 synchronized reserve requirement. All nonemergency generating resources were required to submit tier 2 synchronized reserve offers. All online, nonemergency generating resources were deemed available to provide both tier 1 and tier 2 synchronized reserve in accordance with their ability. Generating resources were required to provide at least 0.1 MW of tier 2 reserve in order to make offers in the tier 2 synchronized reserve market. Unit types that cannot reliably provide synchronized reserve, including nuclear, wind, solar, and energy storage resources, were expected to offer zero MW of tier 2 synchronized reserve. If PJM issued a primary reserve warning, voltage reduction warning, or manual load dump warning, all offline emergency generation capacity resources available to provide energy were required to submit an offer for tier 2 synchronized reserve.[48]

In the first nine months of 2022, the Mid Atlantic Dominion (MAD) Reserve Subzone averaged 5,478.1 MW of tier 2 synchronized reserve offers, and the RTO Reserve Zone averaged 35,043.1 MW of tier 2 synchronized reserve offers (Figure 10-8).

The supply of tier 2 synchronized reserve offered in the first nine months of 2022 was sufficient to cover the ASO hourly requirement net of tier 1 in both the RTO Reserve Zone and the MAD Reserve Subzone.

The largest portion of cleared tier 2 synchronized reserve in the first nine months of 2022 was from demand resources followed by CTs running on natural gas (Table 10-17). Although demand resources were limited to providing no more than 33 percent of the total synchronized reserve requirement, the amount of tier 2 synchronized reserve required in any hour was often much less than the full synchronized reserve requirement because so much of it was met with tier 1 synchronized reserve. This means that in some hours demand resources made up considerably more than 33 percent of the cleared tier 2 MW. Demand resources often offer at a price of $0, do not incur an LOC, and clear even when the price is $0. As a result, their share of credits in the synchronized reserve market was less than their share of cleared MW.

48 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 121 (June 1, 2022).

Table 10-17 Supply of Tier 2 Synchronized Reserve by Resource Type and Fuel Type: January through September, 2022

Resource/Fuel Type	Percent by MW	Percent by Credits
DSR	34.1%	17.3%
CT - Natural Gas	27.3%	31.1%
Combined Cycle	17.5%	28.8%
CT - Oil	9.3%	11.0%
Hydro - Run of River	8.2%	7.0%
Steam - Coal	1.8%	2.7%
Hydro - Pumped Storage	1.5%	1.6%
RICE - Natural Gas	0.2%	0.3%
Steam - Natural Gas	0.1%	0.2%
Steam - Other	0.0%	0.0%
Battery	0.0%	0.0%
CT - Other	0.0%	0.0%
Distributed Gen	0.0%	0.0%
Fuel Cell	0.0%	0.0%
Nuclear	0.0%	0.0%
RICE - Oil	0.0%	0.0%
RICE - Other	0.0%	0.0%
Solar	0.0%	0.0%
Solar + Storage	0.0%	0.0%
Solar + Wind	0.0%	0.0%
Steam - Oil	0.0%	0.0%
Wind	0.0%	0.0%
Wind + Storage	0.0%	0.0%

Demand

The RTO Reserve Zone scheduled and identified an average of 552.0 MW of tier 2 synchronized reserves in the first nine months of 2022. Of this, an average of 545.4 MW was scheduled hourly.

Figure 10-6 and Figure 10-7 show the average monthly synchronized reserve required and the average monthly tier 2 synchronized reserve MW scheduled (PJM scheduled plus self-scheduled) from January 2021 through September 2022, for the MAD Reserve Subzone and the RTO Reserve Zone. In the first nine months of 2021, there were 19 intervals of synchronized reserve shortage and 12 spinning events of which four were longer than 10 minutes. In the first nine months of 2022, there were 30 intervals of synchronized reserve shortage in the dispatch solution and 14 spinning events of which three were longer than 10 minutes. There were 33 intervals of synchronized reserve shortage in the pricing solution. Shortage pricing was used for synchronized reserve during 11 intervals on June 13 alone, causing a higher average price for June.

Figure 10-6 MAD monthly average tier 2 synchronized reserve scheduled MW: January 2021 through September 2022

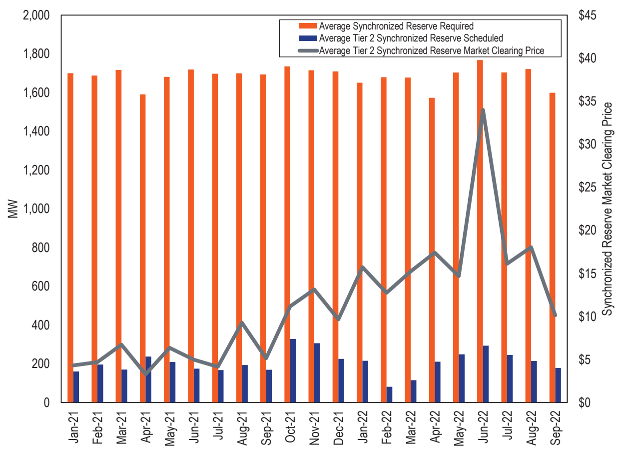
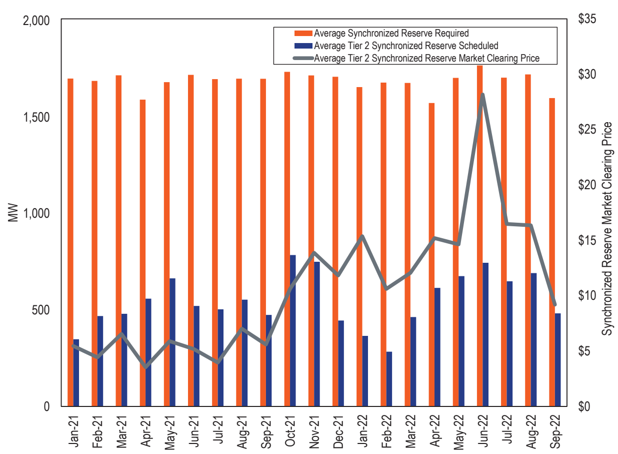


Figure 10-7 RTO monthly average tier 2 synchronized reserve scheduled MW: January 2021 through September 2022



Market Concentration

The average HHI for tier 2 synchronized reserve cleared intervals in the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market in the first nine months of 2022 was 4437, which is defined as highly concentrated. In 68.7 percent of all cleared pricing intervals the maximum market share was greater than or equal to 40 percent.

The average HHI for tier 2 synchronized reserve for cleared pricing intervals of the RTO Zone Tier 2 Synchronized Reserve Market in the first nine months of 2022 was 2898, which is defined as highly concentrated. In 31.6 percent of cleared intervals there was a maximum market share greater than or equal to 40 percent.

In the MAD Subzone, flexible synchronized reserve was 1.0 percent of all tier 2 synchronized reserve in the first nine months of 2022. In the RTO Zone, flexible synchronized reserve was 1.3 percent of all tier 2 synchronized reserve MW in the first nine months of 2022.

The market structure results indicate that the RTO Zone and Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Markets was not structurally competitive.

Market Behavior

Offers

Daily cost-based offers were submitted for each unit by the unit owner. For generators the offer in the first nine months of 2022 included, when relevant, a tier 1 synchronized reserve ramp rate, a tier 1 synchronized reserve maximum, self scheduled status, synchronized reserve availability, synchronized reserve offer quantity (MW), tier 2 synchronized reserve offer price, energy use for tier 2 condensing resources (MW), condense to gen cost, shutdown costs, condense startup cost, condense hourly cost, condense notification time, and spin as a condenser status. The tier 2 synchronized reserve offer price made by the unit owner was subject to an offer cap of marginal cost plus a markup of $7.50 per MW. The tier 1 synchronized reserve ramp rate had to be greater than or equal to the real-time economic ramp rate. If the synchronized reserve ramp rate was greater than the economic ramp rate it had to be justified by the submission of actual data from previous synchronized reserve events.[49] All suppliers were paid the higher of the market clearing price or their offer plus their unit specific opportunity cost. The offer quantity was limited to the economic maximum. PJM monitored this offer by checking to ensure that all offers were greater than or equal to 90 percent of the resource's ramp rate times 10 minutes. A resource that was unable to participate in the synchronized reserve market during a given hour could set its hourly offer to zero MW. Certain defined resource types were not required to offer tier 2 because they could not reliably provide synchronized reserve.

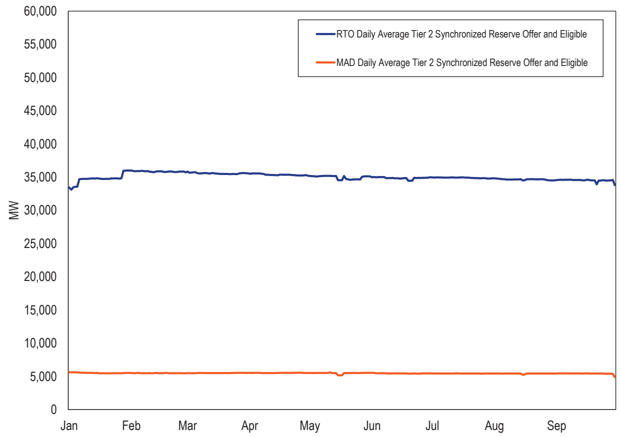
49 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 122 (Oct. 1, 2022).

These include: nuclear, wind, solar, landfill gas and energy storage resources.[50]

Figure 10-8 shows the daily average of hourly offered tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve Subzone.

PJM had a tier 2 synchronized reserve must offer requirement for all generation that was online, nonemergency, and physically able to operate with an output less than dictated by economic dispatch. Tier 2 synchronized reserve offers were made on a daily basis with hourly updates permitted. Daily offers could be changed as a result of maintenance status or physical limitations only and were required regardless of online/offline state.[51] The tier 2 synchronized reserve market was not cleared based on daily offers but based on hourly updates to the daily offers. As a result of hourly updates the actual amount of eligible tier 2 MW could change significantly every hour (Figure 10-8). Changes to the hourly offer status were only permitted when resources were physically unable to provide tier 2. Changes to hourly eligibility levels were the result of online status, minimum/maximum runtimes, minimum notification times, maintenance status, and grid conditions including constraints. However, resource operators could mark their units as unavailable for an hour or block of hours without having to provide a reason. In the first nine months of 2022, synchronized reserve offers averaged 35,043.6 MW in the RTO Zone and 5,478.1 MW in the MAD Subzone.

Figure 10-8 Tier 2 synchronized reserve hourly offer and eligible volume (MW):[52] January through September, 2022



Although tier 2 synchronized reserve had a must offer requirement, there were a large number of hours when many units made themselves unavailable for tier 2 synchronized reserve.

The MMU recommended that the tier 2 synchronized reserve must offer requirement be enforced. The MMU recommended that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer to 0 MW.[53] This recommendation was adopted effective October 1, 2022.

Market Performance

Price

The price of tier 2 synchronized reserve was calculated in real time every five minutes by the LPC market solution for the RTO Reserve Zone and the MAD Subzone. The tier 2 synchronized reserve market price was determined not only by the offer price of each cleared MW of tier 2, but additionally by the net cost of jointly optimizing the dispatch of energy and synchronized reserve. Beginning October 1, 2022, this process applied to all flexible synchronized reserves. For each MW assigned, the clearing engines determine a product substitution price, i.e. the marginal cost of replacing the reserve MW with energy from other resources. The product substitution cost is a function of the LMPs of the MW of reserve, the

50 See *id.*
51 See *id.* ("Regardless of online/offline state, all non-emergency generation capacity resources must submit a daily offer for Tier 2 Synchronized Reserve in eMKT…").

52 These values less than what was previously reported.
53 PJM adopted a new business rule in the third quarter of 2017 to enforce compliance with the tier 2 must offer requirement. PJM entered a zero dollar offer price for all units with a must offer obligation for tier 2 synchronized reserves.

marginal cost of energy for the resources providing reserves, and the minimized cost of substituted MW providing energy. At the margin, the price is the sum of the offer price plus the product substitution cost of the marginal unit(s).[54] The number of marginal units by schedule type is shown in Table 10-18.

Table 10-18 Schedule used for LOC of marginal units in RT SCED Tier 2 Synchronized Reserve Market LOC calculation: January through September, 2022

Number of Marginal Units	Percent of Marginal Units with LOC Based on Cost Schedule	Percent of Marginal Units with LOC Based on Price Schedule
79,073	21.5%	78.5%

In the first nine months of 2022, the RT SCED cleared the RTO tier 2 synchronized reserve market in 63.8 percent of all dispatch solutions. In all other intervals there was enough tier 1 synchronized reserve to cover the synchronized reserve requirement. For intervals when the synchronized reserve requirement could not be met with tier 1, the market cleared an average of 751.2 MW of synchronized reserve (plus 236.1 MW of demand response) at a weighted average price of $12.20 per MWh.

The market clearing price for the MAD Subzone diverged from the RTO Zone in 1,001 intervals during the first nine months of 2022.

Supply, demand, and performance for tier 2 synchronized reserve cleared hours (price > $0) are reflected in the price of synchronized reserve (Table 10-19).

Table 10-19 RTO Zone, average SRMCP and average scheduled, tier 1 estimated and demand response MW in RT SCED market solutions: January 2021 through September 2022

Year	Month	Weighted Average Synchronized Reserve Market Clearing Price	Average Interval Tier 2 Generation Synchronized Reserve Purchased (MW)	Average Interval Tier 1 Synchronized Reserve Esitmate (MW)	Average Interval Demand Response Cleared (MW)
2021	Jan	$7.70	332.9	1,758.2	88.7
2021	Feb	$10.56	459.4	1,851.4	135.9
2021	Mar	$11.43	432.4	1,702.0	122.9
2021	Apr	$6.03	549.3	1,308.5	165.0
2021	May	$7.95	591.4	1,375.8	186.0
2021	Jun	$9.22	466.7	1,696.9	143.1
2021	Jul	$9.20	483.6	1,675.5	177.6
2021	Aug	$13.86	495.3	1,770.6	205.5
2021	Sep	$9.33	432.7	1,779.3	185.0
2021	Oct	$11.52	780.1	1,109.1	250.0
2021	Nov	$14.27	744.3	1,163.2	228.0
2021	Dec	$15.43	440.1	1,625.2	106.7
2021	Average	$10.83	518.7	1,563.7	166.6
2022	Jan	$21.89	357.5	1,713.9	107.4
2022	Feb	$16.17	255.8	1,949.3	99.6
2022	Mar	$14.21	447.5	1,515.3	139.9
2022	Apr	$16.64	594.8	1,154.8	171.5
2022	May	$15.74	602.9	1,476.7	192.0
2022	Jun	$31.01	652.1	1,535.5	219.7
2022	Jul	$17.32	590.1	1,468.2	189.3
2022	Aug	$18.74	656.5	1,432.1	244.5
2022	Sep	$16.47	448.8	1,592.0	212.4
2022	Average	$19.02	514.2	1,534.1	175.7

54 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.9 Synchronized Reserve Market Clearing Price (SRMCP) Calculation, Rev. 121 (July 7, 2022).

Settlement Cost

As a result of changing grid conditions, load forecasts, and unexpected generator performance, the prices of synchronized reserve do not always cover the full cost to customers, including the final LOC for each resource. Because price formation occurs within the hour (on a five minute basis) but inflexible synchronized reserve commitment occurs prior to the hour, the realized, within hour price can be zero even when some tier 2 synchronized reserve is cleared. All resources cleared in the tier 2 synchronized reserve market are guaranteed to be made whole and paid uplift credits in settlement if the SRMCP does not compensate them for their offer plus LOC.

PJM implemented fast start pricing on September 1, 2021. Between September 1, 2021 and December 31, 2021 prices were 2.1 percent higher than in the dispatch run (considering only intervals where the Tier 2 Synchronized Reserve price is greater than $0). In the first nine months of 2022, the average price was 26.1 percent higher in the pricing run than in the dispatch run. The price was above zero in the RTO Zone in 38.6 percent of intervals in the first nine months of 2022 (Table 10-20).

Prices were significantly higher in the first nine months of 2022 than they were in the first nine months of 2021 because of higher load, increased fuel costs and fast start pricing (Table 10-20). The MW weighted synchronized reserve market clearing price was computed for hours when the price was above $0. The market clearing solution includes a constraint that forces all remaining synchronized reserve to be cleared from the MAD Subzone (Figure 10-1) when one of the constraints defining MAD binds. RTO/MAD prices diverged in 1,001 intervals in the first nine months of 2022. In the first nine months of 2022, the MW weighted average tier 2 synchronized reserve clearing price was $16.16 in the RTO Zone and $18.14 in the MAD Subzone.

Table 10-20 RTO Zone tier 2 synchronized reserve MW, credits, price, and cost: January 2021 through September 2022

Year	Month	Tier 2 Generation and DSR Credited MWh	Tier 2 SRMCP Credits	LOC Credits	Weighted Synchronized Reserve Market Clearing Price	Tier 2 Synchronized Reserve Cost	Price / Cost Ratio
2021	Jan	250,410	$1,366,533	$284,557	$5.46	$6.59	82.8%
2021	Feb	309,335	$1,371,901	$1,053,888	$4.44	$7.84	56.6%
2021	Mar	323,201	$2,116,589	$1,256,664	$6.55	$10.44	62.7%
2021	Apr	393,789	$1,393,286	$668,319	$3.54	$5.24	67.6%
2021	May	441,010	$2,600,987	$1,168,654	$5.90	$8.55	69.0%
2021	Jun	336,909	$1,749,251	$1,259,710	$5.19	$8.93	58.1%
2021	Jul	360,204	$1,426,976	$1,252,892	$3.96	$7.44	53.2%
2021	Aug	370,243	$2,598,840	$2,417,882	$7.02	$13.55	51.8%
2021	Sep	314,001	$1,754,993	$1,463,884	$5.59	$10.25	54.5%
2021	Oct	580,156	$6,156,577	$2,457,649	$10.61	$14.85	71.5%
2021	Nov	538,939	$7,479,685	$1,757,937	$13.88	$17.14	81.0%
2021	Dec	330,219	$3,907,943	$859,945	$11.83	$14.44	82.0%
2021		4,548,417	$33,923,562	$15,901,982	$7.46	$10.95	68.1%
2022	Jan	270,905	$4,165,719	$2,469,534	$15.38	$24.49	62.8%
2022	Feb	172,233	$1,828,245	$646,444	$10.61	$14.37	73.9%
2022	Mar	332,184	$4,006,135	$907,088	$12.06	$14.79	81.5%
2022	Apr	426,922	$6,490,248	$1,209,779	$15.20	$18.04	84.3%
2022	May	446,066	$6,528,859	$1,256,883	$14.64	$17.45	83.9%
2022	Jun	468,822	$13,205,921	$3,266,937	$28.17	$35.14	80.2%
2022	Jul	440,293	$7,255,855	$2,395,004	$16.48	$21.92	75.2%
2022	Aug	484,348	$7,920,363	$3,257,132	$16.35	$23.08	70.9%
2022	Sep	324,232	$2,982,950	$917,813	$9.20	$12.03	76.5%
2022		3,366,006	$54,384,294	$16,326,614	$16.16	$21.01	76.9%

Table 10-21 shows the effect of fast start pricing on the synchronized reserve market's monthly weighted average market clearing price from September 2021 through September 2022. The weighted average market clearing price for each month is consistently higher in the pricing run then in the dispatch run.

Table 10-21 Comparison of fast start and dispatch pricing components: September 2021 through September 2022

Year	Month	Pricing Method	Weighted Average Market Clearing Price
2021	Sep	Dispatch	$4.76
		Fast Start	$5.59
2021	Oct	Dispatch	$8.52
		Fast Start	$10.61
2021	Nov	Dispatch	$10.94
		Fast Start	$13.88
2021	Dec	Dispatch	$10.12
		Fast Start	$11.83
2022	Jan	Dispatch	$13.86
		Fast Start	$15.38
2022	Feb	Dispatch	$9.72
		Fast Start	$10.61
2022	Mar	Dispatch	$9.95
		Fast Start	$12.06
2022	Apr	Dispatch	$12.53
		Fast Start	$15.20
2022	May	Dispatch	$11.48
		Fast Start	$14.64
2022	Jun	Dispatch	$23.75
		Fast Start	$28.17
2022	Jul	Dispatch	$11.38
		Fast Start	$16.48
2022	Aug	Dispatch	$12.06
		Fast Start	$16.35
2022	Sep	Dispatch	$7.53
		Fast Start	$9.20

Consolidated Synchronized Reserve

On October 1, 2022, PJM implemented a new reserve market design, consolidating tier 1 and tier 2 reserves into one product. All generation resources capable of providing synchronized reserves have a must offer requirement, and all cleared synchronized reserves have an obligation to perform and receive payment based on the synchronized reserve market clearing price. While synchronized reserve was a real-time only product, prior to October 1, the new reserve market design includes both day-ahead and real-time synchronized reserve markets.

Market Structure

For most resources, synchronized reserves consist of any online capacity not being used for energy that can be achieved within ten minutes from the current dispatch point according to the resource's ramp rate. The PJM market solves an economic dispatch to determine which, if any, of these resources should be backed down to provide reserves. Some nondispatchable and demand side resources can provide synchronized reserves, including storage resources, hydro resources with storage, synchronous condensers, and demand response resources. For both the RTO and the reserve subzone, the day-ahead market clears hourly synchronized reserve assignments, and the real-time market clears five minute synchronized reserves assignments.

Supply

The supply of synchronized reserves consists of all unloaded capacity that can convert to energy in ten minutes from online resources and all synchronized load that can curtail in ten minutes. Any of this capacity that is not offered as dispatchable in the energy market does not have a lost opportunity cost in the security constrained economic dispatch (SCED). This includes synchronous condensers, storage resources, and demand response. Synchronous condensers and demand response are also considered inflexible in the reserve market and require an hourly commitment, which is made by the Ancillary Services Optimizer (ASO) in real time. This means that these resources enter the SCED reserves supply curve with a marginal cost of zero, because PJM is effectively committing them as must run, block loaded reserves.

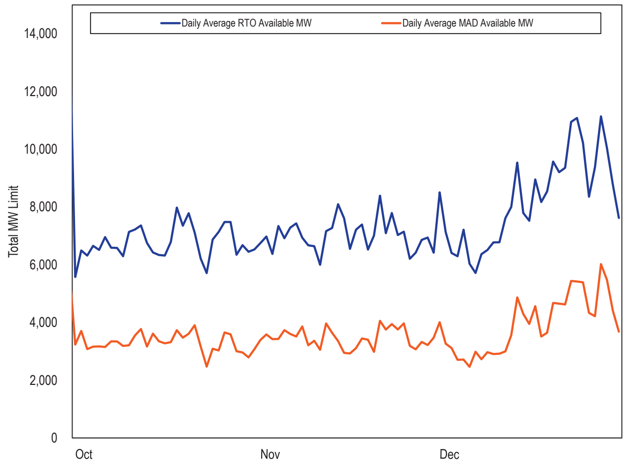
In general, a resource's reserve MW offer is calculated by PJM as the lesser of a resource's 10-minute ramp and the difference between its energy output and its economic maximum output. Hydroelectric generators, energy storage resources, and load response resources must set their own MW offers. A generation resource can request a maximum MW value for its synchronized reserve offer that is lower than its economic maximum if that generator's reserve offer is subject to a physical limitation that cannot be modeled by a segmented hourly ramp rate.[55] Such a request must include documentation and data demonstrating the limitation. Both PJM and the MMU review the request. PJM must respond within 30 days after data supporting the request is submitted, telling the generation owner whether the request was accepted or denied, and if denied, for what reason.

55 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations", § 4.2.2.1 Communication for Reserve Capability Limitation, Rev. 122 (October 1, 2022).

Most resources that make an energy offer are considered available to offer reserves, but not all. Exceptions include nuclear, solar, and wind resources, which must request inclusion in the reserve market, and resources that have been automatically deselected from participating in the reserve market for performance reasons.[56] [57] PJM can temporarily deselect a resource from providing reserves for, among other reasons, failing to reliably follow PJM's dispatch signal. A resource that is deselected for failing to follow PJM's dispatch signal is in violation of its must-offer requirement.[58]

In the last three months of 2022, the average supply of daily offered and eligible synchronized reserve was 7,342.6 MW in the RTO Zone of which 3,570.0 MW was located in the MAD Subzone. Figure 10-9 shows the daily average available synchronized reserve MW, including resources whose synchronized reserve MW is calculated by PJM and resources whose synchronized reserve MW is calculated by the market participant.

Figure 10-9 Daily Average Available Synchronized Reserve: October through December, 2022



Market Concentration

Table 10-22 provides the average HHI and the percent of intervals during which the maximum market share was above 20 percent for the day-ahead and real-time synchronized reserve markets for the last three months of 2022. A market with an HHI below 1000 is defined to be unconcentrated, with an HHI between 1000 and 1800 is defined to be moderately concentrated, and with an HHI above 1800 is defined to be highly concentrated. In the last three months of 2022, the MAD real-time and day-ahead synchronized reserve markets were highly concentrated. In the last three months of 2022, the RTO real-time market synchronized reserve was unconcentrated and the RTO day-ahead market was moderately concentrated.

Table 10-22 Day-ahead and real-time synchronized reserve Average HHI, October through December, 2022[59]

Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%
RTO	RT	868	25.1%
RTO	DA	1043	44.1%
MAD	RT	3257	99.7%
MAD	DA	2410	98.0%

Market Behavior

While for most resources the amount of reserve MW offered is calculated automatically, resources can set their offer price. However, this offer price must be cost based and is capped at the expected value of the synchronized reserve penalty, which equals the average penalty multiplied by the average rate of non-performance multiplied by the probability that an event will occur.[60] These values are listed in Table 10-23. For resources that do not set their offer price, the offer price is treated as $0 per MWh.

Table 10-23 Expected values of the synchronized reserve penalty

Month	Value of Expected Penalty ($/MWh)
Oct	0.02
Nov	0.02
Dec	0.11

Market Performance

Figure 10-10 shows the daily unweighted average prices for synchronized reserve in the real-time and day-ahead markets. Prices were significantly higher during the period of December 23 through December 26, during which PJM experienced widespread outages due to Elliott. During this time there were multiple spin events and shortages of primary and synchronized reserve.

56 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Reserve Market Eligibility, Rev. 122 (October 1, 2022).
57 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3.1 Deselection of Reserve Resources in Real-Time, Rev. 122 (October 1, 2022).
58 See *id.*
59 Concentration is calculated from the scheduled MW, which are used to satisfy the synchronized reserve requirement. It is not calculated from the capped MW, which determine how resources are credited.
60 See PJM. "PJM Manual 15: Cost Development Guidelines," § 4.7 Synchronized Reserve, Rev. 42 (October 28, 2022).

Figure 10-10 Day-ahead and real-time synchronized reserve market clearing prices: October through December, 2022

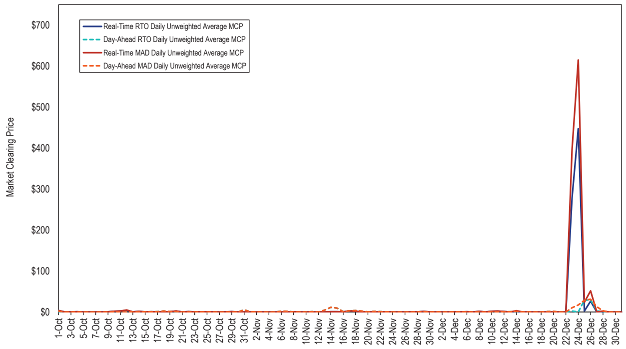


Table 10-24 compares the dispatch-run and pricing-run weighted average prices for the day-ahead and real-time markets. In the last three months of 2022, the pricing-run weighted average price was consistently higher than that of the dispatch run, and the absolute difference and percent difference between the dispatch-run and pricing-run prices was consistently higher in the real-time market.

Table 10-24 Day-ahead and real-time fast start pricing in the synchronized reserve market: October through December, 2022

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2022	Oct	$0.39	$0.44	$0.04	11.2%	$0.42	$0.84	$0.42	99.2%
2022	Nov	$1.38	$1.48	$0.11	7.9%	$0.13	$0.33	$0.20	156.3%
2022	Dec	$2.63	$3.29	$0.65	24.8%	$29.30	$30.95	$1.65	5.6%

Table 10-25 shows total synchronized reserve payments by month for the last three months of 2022. Balancing credits are negative, because, on average, resources buy back their day-ahead positions at higher prices. LOC credits are paid to cover negative balancing credits if PJM has converted the reserve position to energy in the real-time market. LOC credits are also paid to inflexible reserves when prices do not cover their opportunity costs. Shortfall charges are incurred by resources that do not provide their cleared reserve positions in real-time. Negative balancing credits and shortfall charges exceeded day-ahead credits and positive balancing credits in December 2022 due to reserve shortages during Winter Storm Elliott, resulting in negative total credits.

Table 10-25 Total payments and charges by month: October through December, 2022

Year	Month	Total Day-Ahead Credits	Total Balancing MCP Credits	Total LOC Credits	Total Shortfall Charges	Total Credits
2022	Oct	$676,211	($67,992)	$1,711,285	$19,273	$2,300,231
2022	Nov	$2,275,752	($121,388)	$1,357,764	$14,882	$3,497,246
2022	Dec	$4,874,437	($12,713,479)	$14,118,985	$14,636,427	($8,356,484)

Table 10-26 provides the day-ahead and real-time synchronized reserve by resource type and fuel type for the last three months of 2022. A resource's assignment in real time depends on how it clears the day-ahead and real-time markets. A resource cleared in one market is not guaranteed to have cleared in the other market, and resources clearing in both markets need not clear the same amount.

Credits and charges for synchronized reserve have corresponding day-ahead and real-time components. Day-ahead credits depend only on a resource's day-ahead assignment and the day-ahead market clearing price. There are no lost opportunity cost (LOC) credits in the day-ahead market, nor are there any shortfall charges applied to day-ahead assignments when evaluating resource performance. These concepts apply only to the real-time market.

The real-time component is used to supplement the day-ahead credits based on the difference between the real-time and day-ahead assignments. This balancing credit for a resource is the sum of a resource's balancing MCP credit and LOC credit, less its shortfall charge. If a resource clears less MW in real-time than in the day-ahead market, and if it is found to be at fault for this reduction, then the balancing MCP credit is negative. If the resource clears more in real time, then it is positive.

The MW for which a resource is credited at the market clearing price is capped at the lesser of its real-time assignment and the difference between its real-time output and the lesser of its economic maximum and its real-time reserve maximum. During spin events, this capped value is equal to the assigned MW. As it is this capped value for which a resource is credited, Table 10-26 only shows the capped value, excluding the scheduled MW. During Winter Storm Elliott, many resources bought back day-ahead reserve positions at shortage prices based on the ORDCs resulting in negative balancing credits and negative total credits for some resources.

Before the October 1 changes, DSR was limited to being at most 33 percent of the cleared synchronized reserves. This limitation was removed. In the last three months of 2022, DSR was more than 33 percent of the cleared synchronized reserves in 21 of 26,508 five-minute intervals. In all of the 21 intervals, DSR exceeded 33 percent of the RT MW, but not the DA MW. During these 21 intervals, on average, DSR made up 48.9 percent of the total synchronized reserve MW.

Table 10-26 Day-ahead and Real-time Synchronized Reserve by Resource Type and Fuel Type: October through December, 2022

Resource / Fuel Type	Day-Ahead MWh	Real-Time Capped MWh	Day-Ahead Credits	Balancing MCP Credits	LOC Credits	Shortfall Charges	Total Credits
CT - Natural Gas	1,026,381	1,039,432	$1,558,718	($2,890,498)	$6,974,530	$1,070,331	$4,572,419
Steam - Coal	396,596	698,938	$940,337	$2,333,511	$1,917,684	$1,187,984	$4,003,548
DSR	50,396	310,121	$163,038	$1,723,060	$599,522	$328,509	$2,157,110
Steam - Natural Gas	84,216	82,997	$243,503	$883,674	$231,950	$616,436	$742,691
Steam - Other	7,369	5,801	$7,815	$130,998	$101,429	$64,716	$175,526
RICE - Natural Gas	450	1,977	$6,071	$52,790	$14,870	$0	$73,731
CT - Other	4	4	$200	$3,293	$309	$0	$3,802
RICE - Oil	360	33	$8,416	($65,079)	$16,959	$3,640	($43,344)
Steam - Oil	1,011	1,558	$10,758	($246,027)	$27,830	$0	($207,439)
RICE - Other	105,746	10,799	$137,288	($570,660)	$193,708	$193	($239,857)
Hydro - Run of River	288,965	142,414	$211,532	$383,007	$189,296	$1,225,329	($441,495)
CT - Oil	28,974	33,855	$232,282	($1,432,189)	$325,680	$363	($874,589)
Hydro - Pumped Storage	368,167	169,306	$696,352	($948,778)	$710,172	$6,502,206	($6,044,460)
Combined Cycle	2,202,765	1,408,892	$3,610,091	($12,259,960)	$5,886,573	$3,670,873	($6,434,169)
Battery	0	0	NA	NA	NA	NA	NA
Distributed Gen	0	0	NA	NA	NA	NA	NA
Fuel Cell	0	0	NA	NA	NA	NA	NA
Nuclear	0	0	NA	NA	NA	NA	NA
Solar	0	0	NA	NA	NA	NA	NA
Solar + Storage	0	0	NA	NA	NA	NA	NA
Solar + Wind	0	0	NA	NA	NA	NA	NA
Wind	0	0	NA	NA	NA	NA	NA
Wind + Storage	0	0	NA	NA	NA	NA	NA

Synchronized Reserve Performance

In the first nine months of 2022, tier 1 resource owners were paid for the actual amount of synchronized reserve they provided in response to a synchronized reserve event.[61] Tier 2 resource owners, and all synchronized reserve resource owners in the last three months of 2022, were paid for being available but were not paid based on the actual response to a synchronized reserve event. When synchronized reserve resources self schedule or clear the Synchronized Reserve Market they are obligated to provide their full scheduled MW during a synchronized reserve event. Actual synchronized reserve event response is determined by final output minus initial output where final output is the largest output between 9 and 11 minutes after the start of the event, and initial output is the lowest

61 See PJM. "PJM Manual 28: Operating Agreement Accounting", § 6.2.1 Synchronized Reserve Clearing Price Credit, Rev. 87 (July 27, 2022).

output between one minute before the event and one minute after the event.[62] Cleared synchronized reserve resources are obligated to sustain their final output for the shorter of the length of the event or 30 minutes. Penalties are assessed for failure of a scheduled resource to perform during any synchronized reserve event lasting 10 minutes or longer.

In 2022, synchronized reserve performance was not adequate. Compliance with calls to respond to actual synchronized reserve events was significantly less than 100 percent. Table 10-27 shows the average amount of scheduled synchronized reserve MW that responded to events 10 minutes or longer from January 2016 through December 2022. Actual participant performance means that the penalty structure was not adequate to incent performance. From December 23 through December 24, PJM experienced five synchronized reserve events during Elliott. All five of these events were longer than 10 minutes, and three of these events were longer than 30 minutes. Response to these events was poor, significantly lowering the average for the last three months of 2022 seen in Table 10-27.

Table 10-27 Average syncrhonized reserve event response, January 2016 through December 2022

Year	No. of Events Longer than 10 Minutes	Average Percent of Scheduled Synchronized Reserve MW that Responded
2016	7	85.5%
2017	6	87.6%
2018	8	74.2%
2019	3	86.8%
2020	5	59.5%
2021	5	76.9%
2022 (Jan - Sep)	3	51.4%
2022 (Oct - Dec)	7	36.4%

The penalty structure when a resource fails to respond fully to a spinning event has two components. The first component is the forfeiture of awarded SRMCP credits in the amount of the MW of shortfall for the day on which the event occurred. The second component is a retroactive charge applied to the SRMCP credits paid in the Immediate Past Interval (IPI), equal to the sum of, for each scheduled interval within the IPI, the SRMCP multiplied by the minimum of a resource's capped MW assignment during the penalized interval and the resource's penalty obligation on the day of the event. The IPI is calculated as the average number of days since the previous event over the previous two years or, if less, the number of days since the resource last failed to fully respond. Prior to the consolidation of tier 1 and tier 2 synchronized reserves, a resource's penalized MW were equal to the resource's penalty obligation. They were not capped on a per-interval basis at a resource's capped MW assignment, a concept which was introduced on October 1, 2022.

There are several problems with this penalty structure. First, resource owners are permitted to aggregate the response of multiple resources, allowing owners to reduce the penalty obligation of a resource's underresponse by offsetting it with another resource's overresponse.[63] Second, the maximum IPI is calculated using events of any length, even though a resource's compliance is automatically counted as 100 percent for events less than 10 minutes in length, shortening the applied IPI significantly. Third, the second component of the penalty only applies to the SRMCP credits awarded during the IPI, ignoring the LOC credits, even though a large portion of credits is awarded for LOC.

Hence, the penalty structure for synchronized reserve nonperformance is inadequate for providing appropriate performance incentives. Under the penalty structure, it is possible for a resource to not respond to any spin events and yet still be paid for providing synchronized reserve. The MMU continues to recommend that the maximum IPI be defined as the average number of days since the previous spinning event 10 minutes or longer and that the penalty's retroactive charges include the LOC credits in addition to the SRMCP credits. If only events 10 minutes or longer were considered, then the maximum IPI would increase to 86 days from its current level of 22 days.[64] However, implementing this change alone might still have been insufficient to ensure proper response.

The MMU also continues to recommend that aggregation not be permitted to offset resource-specific penalties for failure to respond to a synchronized reserve event. Including aggregate responses from all online resources weakens the incentive to perform and creates an incentive to withhold reserves from other resources. Synchronized reserve commitment is resource specific, so the obligation to respond should also be resource specific.

62 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements, Rev. 122 (Oct. 1, 2022).

63 See PJM. "PJM Manual 28: Operating Agreement Accounting," § 6.3 Charges for Synchronized Reserve, Rev. 88 (Oct. 1, 2021).

64 The MMU recommended maximum IPI was previously reported as 76 days.

Table 10-28 compares the outcomes of the PJM penalty structure for 2022 with the outcomes of the proposed MMU penalty structure following its recommendations. In 2022, there were 10 spinning events that lasted 10 minutes or longer: one on April 13, one on May 16, one on May 23, one on October 29, one on November 29, two on December 23, and three on December 24 (Table 10-29). Due to long periods of shortage pricing during Elliott, the day of event shortfall charges were significantly higher than the retroactive shortfall charges. The retroactive shortfall penalties, although applied to much longer periods, used much smaller market clearing prices.

Table 10-28 Comparison of tier 2 shortfall penalties current IPI vs. MMU recommended: 2022

Penalty Type	Current PJM Penalty	MMU Recommended Penalty
Day Of Event	$14,714,652	$17,130,071
Retroactive Charges	$2,745,604	$9,901,831
Total Penalties	$17,460,256	$27,031,903

Spinning event response data as reported by PJM at the Operating Committee meetings is shown in Table 10-29. The tier 1 estimate was from the most recent RT SCED market solution prior to the spinning event. The tier 1 estimate included estimated ramp only from the units that were eligible and excluded resources that have ramp available but are not part of the estimate.

Tier 1 synchronized reserve that responded to a spinning event received a bonus payment of $50 per MWh, based on a calculation using SCADA data, regardless of whether PJM included those reserves in the estimate.

Table 10-29 shows synchronized reserve event response compliance for events that lasted 10 minutes or longer as reported by PJM, using only response from estimated and cleared synchronized reserves. In the first nine months of 2022, there were three events that were 10 minutes or longer. In the last three months of 2022, there were seven events that were 10 minutes or longer, of which two events lasted over an hour and one event lasted between 30 minutes and an hour. Actual synchronized reserve response is the total increase in MW from all resources from the moment the spinning event is called to 10 minutes after. To determine the actual tier 1 response, the calculation would subtract tier 2 response, changes in assigned regulation output (net compliance level to both RegA and RegD), and changes to net power flow across PJM's interface boundary. The overall response to spinning events was adequate or more than adequate to meet NERC requirements, in which the ACE must return to the lesser of 0 and the value of the ACE before the disturbance that caused the event.[65] PJM not only corrects the ACE disturbance that led to the event but over corrects. In all three of the spinning events in the first nine months of 2022, the ACE recovered not just to the NERC required level but overshoots. In five of the seven events in the last three months of 2022, the ACE was overcorrected. On one of the events on December 23, the ACE recovered but then fell again within 30 minutes from the start of the event. On December 24, three events occurred. As seen in Figure 3-53, during these three events, ACE recovered shortly before falling again before the next event.

One of the reasons for consolidating tier 1 and tier 2 reserves on October 1, 2022, was to improve the performance of synchronized reserve during spinning events. Consolidation gives all synchronized reserves a clear obligation to perform and no longer relies on resources that did not clear reserves. Performance during synchronized reserves events in the last three months of 2022 was worse than in the first nine months of 2022.

65 See PJM. "PJM Manual 12: Balancing Operations," Rev. 47 (Oct. 1, 2022) Attachment D.

Table 10-29 Synchronized reserve events 10 minutes or longer, response compliance as reported by PJM[66], RTO Reserve Zone: January 2019 through December 2022

Spin Event	Duration (Minutes)	Tier 1 Estimate	Response from Tier 1 Estimated (MW)	Tier 2 Scheduled (MW)	Tier 2 Response (MW)	Tier 2 Penalty (MW)	Estimated Tier 1 Response Percent	Tier 2 Response Percent
23-Sep-2019 1207 (EPT)	11	1,485.1	1,212.1	723.2	632.1	91.1	81.6%	87.4%
01-Oct-2019 1456 (EPT)	11	265.4	143.7	1,177.4	1,016.4	161.0	54.1%	86.3%
2019 Average	11	924.7	664.1	723.2	632.1	91.1	71.8%	87.4%
18-Feb-2020 2015 (EPT)	10	2,216.1	1,434.8	40.0	1.7	38.3	64.7%	4.3%
06-Jul-2020 2122 (EPT)	10	1,464.0	526.1	479.7	415.1	64.6	35.9%	86.5%
25-Jul-2020 1639 (EPT)	11	868.4	421.6	302.3	264.8	37.5	48.5%	87.6%
10-Sep-2020 0029 (EPT)	10	1,275.4	453.6	782.6	782.6	0.0	35.6%	100.0%
16-Dec-2020 1649 (EPT)	10	268.4	196.9	527.6	413.2	114.4	73.4%	78.3%
2020 Average	10	1,218.5	606.6	426.4	375.5	51.0	49.7%	59.5%
09-Mar-2021 0750 (EPT)	10	1,354.9	635.4	884.0	540.8	343.2	46.9%	61.2%
30-Apr-2021 1630 (EPT)	12	1,487.6	610.2	508.3	407.2	101.1	41.0%	80.1%
26-May-2021 1017 (EPT)	10	1,138.4	811.0	685.2	600.2	85.0	71.2%	87.6%
23-Aug-2021 1644 (EPT)	18	879.8	597.5	896.2	667.1	229.1	67.9%	74.4%
12-Nov-2021 1725 (EPT)	12	510.0	606.7	890.7	714.6	176.1	119.0%	80.2%
2021 Average	12	1,074.1	652.2	772.9	586.0	186.9	69.2%	76.7%
13-Apr-2022 1725 (EPT)	28	651.9	390.0	880.6	718.4	162.2	59.8%	81.6%
16-May-2022 1532 (EPT)	11	1,490.0	895.3	295.0	91.8	203.2	60.1%	31.1%
23-May-2022 1717 (EPT)	15	757.7	670.4	1,062.2	707.8	354.4	88.5%	66.6%
29-Oct-2022 1412 (EPT)	12			1,857.9	567.1	1,290.8		30.5%
29-Nov-2022 1630 (EPT)	17			1,785.3	949.0	836.3		53.2%
23-Dec-2022 1014 (EPT)	11			1,791.4	948.9	842.5		53.0%
23-Dec-2022 1617 (EPT)	111			1,845.6	812.3	1,033.3		44.0%
24-Dec-2022 0501 (EPT)	26			1,766.5	329.9	1,436.6		18.7%
24-Dec-2022 0223 (EPT)	31			1,664.8	534.7	1,130.1		32.1%
24-Dec-2022 0423 (EPT)	88			1,097.0	258.6	838.4		23.6%
2022 Average	35	967	652	1405	592	813	69.5%	43.4%

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[67] [68] A disturbance is defined as loss of the lesser of 900 MW or 80 percent of the largest single contingency within 60 seconds. In the absence of a disturbance, PJM operators have used synchronized reserve as a source of energy to provide relief from low ACE.

The risk of using synchronized reserves for energy or any other nondisturbance reason is that it reduces the amount of synchronized reserve available for a disturbance. Disturbances are unpredictable. Synchronized reserve has a requirement to sustain its output for only up to 30 minutes. When the need is for reserve extending past 30 minutes, secondary reserve is the appropriate source of the response.

From January 2018 through December 2022, PJM experienced 89 synchronized reserve events, approximately 1.9 events per month, with an average duration of 11.5 minutes. Table 10-30 shows these events with their region and their duration rounded to the nearest minute.

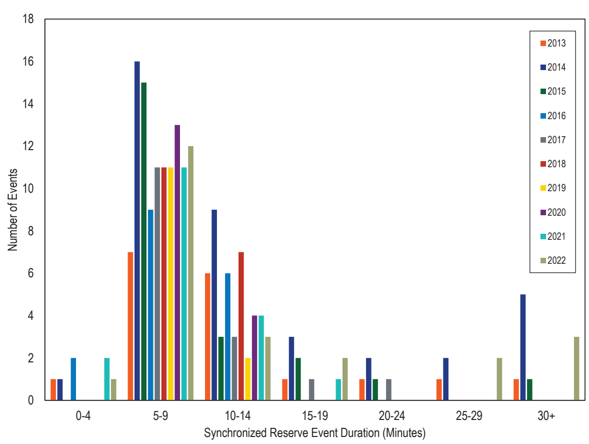
66 *See, for example*, "Systems Operations Report," PJM presentation to the Operating Committee. (April 14, 2022) <https://www.pjm.com/-/media/committees-groups/committees/oc/2022/20220414/item-02---review-of-operating-metrics.ashx> at 10.
67 *2013 State of the Market Report for PJM*, Appendix F – PJM's DCS Performance, at 451–452.
68 See PJM. "PJM Manual 12: Balancing Operations," § 4.1.2 Loading Reserves, Rev. 47 (Oct. 1, 2022).

Table 10-30 Synchronized reserve events: January 2018 through December 2022[69]

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
01-Jan-2018 0241 (EPT)	RTO	7	20-Jan-2020 1406 (EPT)	MAD	8	03-Jan-2022 1227 (EPT)	RTO	9
03-Jan-2018 0300 (EPT)	RTO	13	23-Jan-2020 1617 (EPT)	RTO	9	03-Mar-2022 1220 (EPT)	RTO	7
07-Jan-2018 1415 (EPT)	RTO	9	07-Feb-2020 1206 (EPT)	RTO	6	06-Apr-2022 1145 (EPT)	RTO	10
12-Apr-2018 1328 (EPT)	RTO	10	08-Feb-2020 0344 (EPT)	RTO	8	13-Apr-2022 1725 (EPT)	RTO	28
04-Jun-2018 1022 (EPT)	RTO	6	10-Feb-2020 2015 (EPT)	RTO	9	14-Apr-2022 0931 (EPT)	RTO	8
29-Jun-2018 1521 (EPT)	RTO	9	18-Feb-2020 1116 (EPT)	RTO	10	16-May-2022 1532 (EPT)	RTO	11
30-Jun-2018 0946 (EPT)	RTO	11	08-Mar-2020 0517 (EPT)	MAD	5	16-May-2022 1553 (EPT)	RTO	10
04-Jul-2018 1056 (EPT)	RTO	7	13-Apr-2020 2001 (EPT)	RTO	8	23-May-2022 1717 (EPT)	RTO	15
10-Jul-2018 1545 (EPT)	RTO	13	03-May-2020 1229 (EPT)	RTO	6	26-May-2022 1409 (EPT)	RTO	6
23-Jul-2018 0902 (EPT)	RTO	8	06-Jul-2020 2122 (EPT)	RTO	10	22-Jun-2022 1506 (EPT)	RTO	7
23-Jul-2018 1543 (EPT)	RTO	6	24-Jul-2020 0103 (EPT)	RTO	9	27-Jun-2022 1701 (EPT)	RTO	9
24-Jul-2018 1617 (EPT)	RTO	7	25-Jul-2020 1639 (EPT)	MAD	11	07-Jul-2022 1721 (EPT)	RTO	8
12-Aug-2018 1106 (EPT)	RTO	11	10-Sep-2020 0019 (EPT)	RTO	10	26-Sep-2022 0339 (EPT)	RTO	6
13-Sep-2018 0947 (EPT)	RTO	7	10-Oct-2020 1852 (EPT)	RTO	8	29-Sep-2022 1025 (EPT)	RTO	6
14-Sep-2018 1324 (EPT)	RTO	7	12-Oct-2020 0429 (EPT)	RTO	9	29-Oct-2022 1412 (EPT)	RTO	12
26-Sep-2018 1908 (EPT)	RTO	8	13-Nov-2020 0746 (EPT)	RTO	6	04-Nov-2022 1503 (EPT)	RTO	4
30-Sep-2018 1129 (EPT)	RTO	11	16-Dec-2020 1638 (EPT)	MAD	10	14-Nov-2022 22:01 (EPT)	RTO	7
30-Oct-2018 1040 (EPT)	RTO	11				29-Nov-2022 1630 (EPT)	RTO	17
			24-Jan-2021 2232 (EPT)	RTO	6	23-Dec-2022 1014 (EPT)	RTO	11
22-Jan-2019 2230 (EPT)	RTO	8	09-Mar-2021 0751 (EPT)	RTO	11	23-Dec-2022 1617 (EPT)	RTO	111
31-Jan-2019 0126 (EPT)	RTO	5	13-Apr-2021 2005 (EPT)	RTO	9	24-Dec-2022 0501 (EPT)	RTO	26
31-Jan-2019 0926 (EPT)	RTO	9	30-Apr-2021 2030 (EPT)	RTO	12	24-Dec-2022 0223 (EPT)	RTO	31
25-Feb-2019 0025 (EPT)	RTO	9	26-May-2021 1417 (EPT)	RTO	10	24-Dec-2022 0423 (EPT)	RTO	88
03-Mar-2019 1231 (EPT)	RTO	9	21-Jun-2021 0554 (EPT)	RTO	7			
06-Mar-2019 2206 (EPT)	RTO	9	23-Jun-2021 0333 (EPT)	RTO	5			
27-Jul-2019 2331 (EPT)	RTO	7	21-Jul-2021 1828 (EPT)	RTO	5			
11-Aug-2019 1214 (EPT)	RTO	8	25-Jul-2021 1617 (EPT)	RTO	6			
03-Sep-2019 1339 (EPT)	MAD	9	23-Aug-2021 1644 (EPT)	RTO	18			
23-Sep-2019 1606 (EPT)	RTO	11	24-Aug-2021 1038 (EPT)	RTO	8			
01-Oct-2019 1856 (EPT)	RTO	11	27-Sep-2021 1656 (EPT)	RTO	8			
11-Dec-2019 2108 (EPT)	RTO	8	11-Oct-2021 0923 (EPT)	RTO	9			
18-Dec-2019 1507 (EPT)	RTO	9	16-Oct-2021 0130 (EPT)	RTO	8			
			12-Nov-2021 1325 (EPT)	RTO	12			
			30-Nov-2021 0540 (EPT)	RTO	9			
			30-Nov-2021 0957 (EPT)	RTO	9			
			08-Dec-2021 0504 (EPT)	RTO	7			

Figure 10-11 shows spin event durations over the past five years.[70] Some events last longer than 30 minutes. Beyond 30 minutes reserves no longer have an obligation to perform. It is not clear what resources are instructed or expected to do after the 30 minute performance obligation. This ambiguity applies to three synchronized reserve events during Winter Storm Elliott, which all lasted longer than 30 minutes.

Figure 10-11 Synchronized reserve events duration distribution curve: January 2013 through December 2022



69 For full history of spinning events, see the *2019 State of the Market Report for PJM*, Appendix E - Ancillary Service Markets.
70 These durations were rounded to the nearest minute in previous reports. They are no longer rounded.

Nonsynchronized Reserve Market

Nonsynchronized reserve consists of MW available within 10 minutes but not synchronized to the grid. Startup time for nonsynchronized reserve resources is not subject to testing and is based on parameters in offers submitted by resource owners. There is no defined requirement for nonsynchronized reserves. It is available to meet the primary reserve requirement. Generation resources that have designated their entire output as emergency are not eligible to provide nonsynchronized reserves. Generation resources that are not available to provide energy are not eligible to provide nonsynchronized reserves.

The October 1, 2022, reserve market changes introduced a day ahead market for nonsynchronized reserves and removed the calculation of lost opportunity costs for offline units. Offline units cannot be dispatched to provide energy, because PJM has not called on them to come online, so they do not have a lost opportunity to provide energy. The implications are that the supply curve for nonsynchronized reserve has a price of zero and there are no more uplift credits paid when LMP is higher than the incremental cost of nonsynchronized reserve units.

PJM defines the demand curve for nonsynchronized reserve and PJM defines the supply curve based on nonemergency generation resources that are available to provide energy and can start in 10 minutes or less. Since nonsynchronized reserve is a lower quality product, its clearing price is less than or equal to the synchronized reserve market clearing price. In most market intervals, the nonsynchronized reserve clearing price is zero.

Market Structure

Demand

After filling the synchronized reserve requirement, the balance of primary reserve can be made up by the most economic combination of synchronized and nonsynchronized reserve. The average scheduled hourly nonsynchronized reserve in the RTO Zone in the first nine months of 2022 was 1,122.7 MW. The average scheduled nonsynchronized reserve in the MAD Subzone for primary reserve was 1,109.7 MW. In the RTO Zone, in the last three months of 2022, the average real-time scheduled nonsynchronized reserve was 879.1 MW and the average day-ahead scheduled nonsynchronized reserve was 1,354.5 MW. In the MAD Subzone, in the last three months of 2022, the average real-time scheduled nonsynchronized reserve was 132.8 MW and the average day-ahead scheduled nonsynchronized reserve was 419.2 MW.

Supply

There are no offers for nonsynchronized reserve. The market solution considers the available supply of nonsynchronized reserve to be all generation resources currently not synchronized to the grid but available and capable of providing energy within 10 minutes. Generators that have set themselves as unavailable or have set their output to be emergency only will not be considered. The market solution considers the offered MW to be the lesser of the economic maximum or the ramp rate times 10 minutes minus the startup and notification time. The market supply curve is constructed from the nonsynchronized units' opportunity cost of providing reserves. PJM and generation owners may agree upon exceptions to the requirements.

Prior to October 1, 2022, generators could offer units into the nonsynchronized reserve market without offering to start for energy in 10 minutes or less under special arrangement with PJM. This provision was removed from the Operating Agreement, resulting in a reduction in the total amount of nonsynchronized reserve in the market. The current calculation of available nonsynchronized reserve is more accurate, because only units that the market can commit for energy in 10 minutes are included.

Resources that generally qualify as nonsynchronized reserve include run of river hydro, pumped hydro, combustion turbines, combined cycles that can start in 10 minutes or less, and diesels. In the first nine months of 2022, an average of 1,122.7 MW of nonsynchronized reserve was scheduled per five minute interval out of 2,015.6 eligible MW as part of the primary reserve requirement in the RTO Zone. In the last three months of 2022, an average of 880.5 MW of nonsynchronized reserve was scheduled per five minute interval out of 1,659.4 eligible MW as part of the primary reserve requirement in the RTO Zone.

Table 10-31 provides the day-ahead and real-time nonsynchronized reserve by resource type and fuel type for the last three months of 2022. Unlike synchronized reserve, the amount of MW credited for nonsynchronized reserve is not capped and there is no concept of shortfall MW.

Table 10-31 Day-ahead and real-time nonsynchronized reserve by resource type and fuel type: October through December, 2022

Resource / Fuel Type	Day-Ahead MWh	Real-Time Scheduled MWh	Day-Ahead Credits	Balancing MCP Credits	LOC Credits	Total Credits
Hydro - Run of River	0	414,648	$0	$81,049	$0	$81,049
RICE - Oil	4,324	1,350	$3,593	$8,135	$0	$11,727
CT - Other	6,625	2,246	$5,737	($16)	$0	$5,721
RICE - Other	0	87	$0	$0	$0	$0
CT - Oil	642,651	289,845	$557,077	($4,796,696)	$0	($4,239,619)
CT - Natural Gas	751,230	561,704	$259,447	($6,041,758)	$140,688	($5,641,623)
Hydro - Pumped Storage	1,587,160	672,132	$0	($13,928,768)	$468,948	($13,459,820)
Battery	0	0	NA	NA	NA	NA
Combined Cycle	0	0	NA	NA	NA	NA
DSR	0	0	NA	NA	NA	NA
Distributed Gen	0	0	NA	NA	NA	NA
Fuel Cell	0	0	NA	NA	NA	NA
Nuclear	0	0	NA	NA	NA	NA
RICE - Natural Gas	0	0	NA	NA	NA	NA
Solar	0	0	NA	NA	NA	NA
Solar + Storage	0	0	NA	NA	NA	NA
Solar + Wind	0	0	NA	NA	NA	NA
Steam - Coal	0	0	NA	NA	NA	NA
Steam - Natural Gas	0	0	NA	NA	NA	NA
Steam - Oil	0	0	NA	NA	NA	NA
Steam - Other	0	0	NA	NA	NA	NA
Wind	0	0	NA	NA	NA	NA
Wind + Storage	0	0	NA	NA	NA	NA

Market Performance

The settled price of nonsynchronized reserve is calculated in real time every five minutes for the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone.

Figure 10-12 shows the daily average nonsynchronized reserve market clearing price (NSRMCP) and average credited MW for the RTO Zone. In the first nine months of 2022, the weighted average nonsynchronized market clearing price for all intervals was $0.25 per MWh and the average nonsynchronized reserve credited was 1,122.7 MW. In the last three months of 2022, in the RTO Zone, the real-time weighted average nonsynchronized market clearing price for all intervals was $1.74 per MWh and the day-ahead weighted average price was $3.31 per MWh. Shortage pricing for primary reserve in the RTO was used for 242 intervals in 2022 (Table 10-32). The drop in the quantity of nonsynchronized reserves on October 1, 2022, resulted from the removal of provision allowing for special arrangements with PJM to include resources as nonsynchronized reserves when they did not otherwise qualify under the rules.

Figure 10-12 Daily weighted average RTO Zone nonsynchronized reserve market clearing price and MW purchased: January through December, 2022

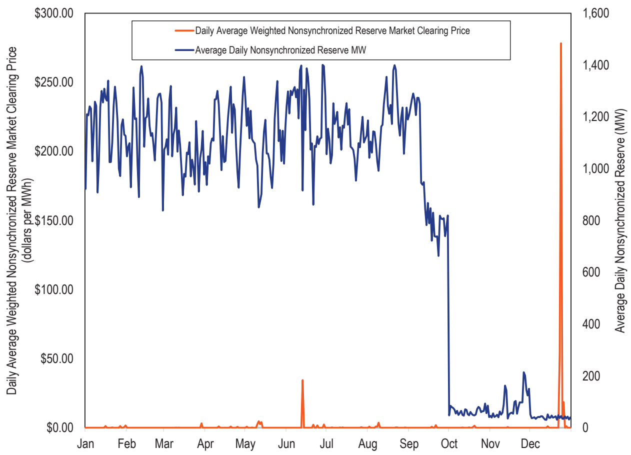


Table 10-32 Summary of Shortage Pricing: 2022

Date	Intervals with Shortage Pricing	Unweighted Average Price
31-Jan-2022	1	$300.00
13-Jun-2022	35	$731.71
23-Dec-2022	71	$801.04
24-Dec-2022	134	$714.50
26-Dec-2022	1	$850.00

Table 10-33 shows the effect of fast start pricing on the nonsynchronized reserve market's monthly weighted average market clearing price since September 2021. The weighted average market clearing price for each month is consistently higher in the pricing run than in the dispatch run. In the first nine months of 2022, the average price from the pricing run was 20.1 percent higher than the average price from the dispatch run.

Table 10-33 Comparison of fast start and dispatch pricing components: September 2021 through December 2022

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2021	Sep	NA	NA	NA	NA	$0.16	$0.20	$0.04	27.2%
2021	Oct	NA	NA	NA	NA	$0.60	$0.78	$0.18	29.5%
2021	Nov	NA	NA	NA	NA	$0.95	$1.19	$0.24	25.6%
2021	Dec	NA	NA	NA	NA	$0.02	$0.04	$0.02	115.8%
2022	Jan	NA	NA	NA	NA	$0.10	$0.13	$0.03	26.5%
2022	Feb	NA	NA	NA	NA	$0.00	$0.00	$0.00	34.8%
2022	Mar	NA	NA	NA	NA	$0.08	$0.08	$0.00	3.6%
2022	Apr	NA	NA	NA	NA	$0.06	$0.07	$0.01	16.8%
2022	May	NA	NA	NA	NA	$0.26	$0.39	$0.13	50.2%
2022	Jun	NA	NA	NA	NA	$0.91	$1.02	$0.12	12.7%
2022	Jul	NA	NA	NA	NA	$0.02	$0.04	$0.02	142.3%
2022	Aug	NA	NA	NA	NA	$0.11	$0.18	$0.07	60.3%
2022	Sep	NA	NA	NA	NA	$0.05	$0.06	$0.01	14.2%
2022	Oct	$0.18	$0.11	($0.07)	(38.3%)	$0.01	$0.09	$0.08	1,061.3%
2022	Nov	$0.52	$0.51	($0.01)	(1.8%)	$0.01	$0.02	$0.01	47.5%
2022	Dec	$0.27	$0.30	$0.02	8.2%	$5.32	$5.00	($0.32)	(6.0%)

In the first nine months of 2022, the average price of nonsynchronized reserve was $0.25 per MWh and the average credit for nonsynchronized reserve was $2.11 per MWh. In the last three months of 2022, the weighted average price of nonsynchronized reserve was $1.74 per MWh and the average credit for nonsynchronized reserves was -$4.22 per MWh.

Resources that are not synchronized to the grid are generally off because it is not economic for them to produce energy. A resource scheduled for nonsynchronized reserve is obligated to remain unsynchronized even if its LMP increases above its energy offer. In that case, in the first nine months of 2022, PJM paid the unit LOC. The LOC calculation did not consider the start cost or the no load cost of committing the unit for energy, which would have reduced the LOC in almost all cases. In fact, in its filing to change the reserve market design, PJM explained that nonsynchronized reserves have no lost opportunity cost.[71] These payments were removed on October 1, 2022.

Table 10-34 shows total synchronized reserve payments by month for the last three months of 2022. During Elliot, reserve providers had to buy back day-ahead cleared reserves at shortage-level prices in real time when they were on a forced outage, leading to a large negative total of balancing MCP credits.

Table 10-34 Total payments and charges by month: September 2021 through December, 2022

Year	Month	Day-Ahead Credits	Real-Time and Balancing MCP Credits	LOC Credits	Shortfall Charges	Total Credits
2021	Jan	NA	$34,155	$499,224	NA	$533,379
2021	Feb	NA	$111,008	$487,273	NA	$598,281
2021	Mar	NA	$249,824	$1,362,200	NA	$1,612,024
2021	Apr	NA	$71,052	$354,466	NA	$425,519
2021	May	NA	$279,185	$1,513,586	NA	$1,792,770
2021	Jun	NA	$103,047	$862,212	NA	$965,259
2021	Jul	NA	$105,339	$671,088	NA	$776,427
2021	Aug	NA	$216,893	$2,393,311	NA	$2,610,204
2021	Sep	NA	$153,683	$1,398,592	NA	$1,552,275
2021	Oct	NA	$545,065	$883,537	NA	$1,428,602
2021	Nov	NA	$937,357	$1,977,144	NA	$2,914,501
2021	Dec	NA	$31,362	$1,534,311	NA	$1,565,673
2022	Jan	NA	$139,595	$7,911,788	NA	$8,051,383
2022	Feb	NA	$3,118	$324,338	NA	$327,456
2022	Mar	NA	$88,940	$328,184	NA	$417,124
2022	Apr	NA	$76,678	$487,396	NA	$564,075
2022	May	NA	$328,203	$1,259,895	NA	$1,588,098
2022	Jun	NA	$922,276	$977,221	NA	$1,899,497
2022	Jul	NA	$35,348	$629,372	NA	$664,719
2022	Aug	NA	$182,222	$1,022,870	NA	$1,205,091
2022	Sep	NA	$43,553	$667,112	NA	$710,665
2022	Oct	$137,051	($13,639)	$1,051	NA	$124,464
2022	Nov	$395,965	$1,731	$0	NA	$397,696
2022	Dec	$292,838	($24,666,147)	$608,585	NA	($23,764,724)

Secondary Reserve

PJM defines secondary reserve as reserves (online or offline available for dispatch) that can be converted to energy in 30 minutes. There is no NERC standard for secondary reserve. Prior to October 1, 2022, PJM defined a 30 minute reserve requirement but did not have a defined reserve product to maintain this reserve requirement in real time.[72] As of October 1, 2022, PJM has a 30 minute reserve market in both the day-ahead and real-time markets.

Prior to October 1, 2022, PJM maintained a day-ahead, offer based market for 30 minute day-ahead reserve. The Day-Ahead Scheduling Reserve Market (DASR) had no performance obligations except that a unit which cleared the DASR market was required to be available for dispatch in real time.[73] As of October 1, 2022, any resource that clears secondary reserves has an obligation in real-time. Failure to convert offline secondary reserves to energy at PJM's request results in shortfall charge for all cleared secondary reserves for the operating day.

Day-Ahead Scheduling Reserve (DASR)

The DASR market results and conclusions only apply to the first nine months of 2022.

Market Structure

Supply

Both generation and demand resources were eligible to offer DASR. DASR offers consisted of price only. Available DASR MW were calculated by the market clearing engine. DASR MW were the lesser of the energy ramp rate per minute for online units times 30 minutes, or the economic maximum MW minus the day-ahead dispatch point. For offline resources capable of being online in 30 minutes, the DASR quantity was the economic maximum. In the first nine months of 2022, the DASR hourly average purchased was 4,820.4 MW.[74]

71 See *PJM Interconnection, L.L.C.*, "Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C.," Docket No. EL19-58 (March 29, 2019) at 84.

72 The reserve market changes, effective October 1, 2022, define a 30-minute reserve service which could be satisfied by a secondary reserve product cleared in the day-ahead and real-time markets.

73 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 10.5 Aggregation for Economic and Emergency Demand Resources, Rev. 121 (July 7, 2022).

74 The average hourly available DASR MW are modified from previously reported values because of a calculation error which has been fixed.

PJM excludes resources that cannot reliably provide reserves in real time from participating in the DASR market. Such resources include nuclear, run of river hydro, self-scheduled pumped hydro, wind, solar, and energy storage resources.[75] The intent was to limit cleared DASR resources to those resources actually capable of providing reserves in the real-time market. Owners of excluded resources could request an exemption from their default ineligibility.

Of the scheduled DASR MW cleared in the first nine months of 2022, 78.7 percent was from CTs (Table 10-35).

Table 10-35 Scheduled DASR by fuel and unit type: January through September, 2022

Resource / Fuel Type	Percentage of DASR MW	Percentage of DASR Credits
CT - Natural Gas	61.0%	61.4%
CT - Oil	17.7%	17.7%
Hydro - Pumped Storage	12.9%	4.3%
Combined Cycle	4.3%	9.2%
Steam - Coal	3.4%	3.5%
RICE - Oil	0.3%	0.9%
Steam - Natural Gas	0.2%	2.4%
RICE - Other	0.1%	0.4%
RICE - Natural Gas	0.0%	0.1%
Steam - Other	0.0%	0.1%
Steam - Oil	0.0%	0.0%
CT - Other	0.0%	0.0%
Battery	0.0%	0.0%
DSR	0.0%	0.0%
Distributed Gen	0.0%	0.0%
Fuel Cell	0.0%	0.0%
Hydro - Run of River	0.0%	0.0%
Nuclear	0.0%	0.0%
Solar	0.0%	0.0%
Solar + Storage	0.0%	0.0%
Solar + Wind	0.0%	0.0%
Wind	0.0%	0.0%
Wind + Storage	0.0%	0.0%

Demand

Secondary reserve (30 minute reserve) requirements were determined by PJM for each reliability region. In the Reliability*First* (RFC) region, secondary reserve requirements were calculated based on historical under forecasted load rates and generator forced outage rates.[76] The DASR requirement was calculated daily and was equal to the peak load forecast for the ReliabilityFirst region (RFC) and EKPC times the sum of the forced outage rate and the load forecast error, plus Dominion's share of the VACAR contingency reserve commitment. Effective November 1, 2021, through September 30, 2022, the day-ahead scheduling reserve requirement was 4.40 percent of the peak load forecast, based on a 2.03 percent LFE component and a 2.38 percent FOR component. The DASR requirement was applicable for all hours of the operating day.

The DASR requirement could be increased by PJM operators under conditions of "hot weather or cold weather alert or max emergency generation alert or other escalating emergency."[77] The amount of additional DASR MW that could be required was the Adjusted Fixed Demand (AFD) determined by a Seasonal Conditional Demand (SCD) factor.[78] The SCD factor was calculated separately for the winter (November through March) and summer (April through October) seasons. The SCD factor was calculated every year based on the top 10 peak load days from the prior year. For November 2021 through October 2022, the SCD values were 5.84 percent for winter and 4.06 percent for summer. PJM Dispatch could also schedule additional Day-Ahead Scheduling Reserves as deemed necessary for conservative operations.[79] PJM defined the reasons for conservative operations to include, potential fuel delivery issues, forest/brush fires, extreme weather events, environmental alerts, solar disturbances, unknown grid operating state, physical or cyber attacks.[80] The result is substantial discretion for PJM to increase the demand for DASR under a variety of circumstances. PJM invoked adjusted fixed demand in 547 hours during the first nine months of 2022. The MMU recommended that PJM modify the DASR market to ensure that all resources cleared incur a real-time performance obligation. The MMU further recommended that PJM attach a reason code to all hours when adjusted fixed demand is dispatched. The recommendations were adopted effective October 1, 2022, with the market changes for the new secondary reserve product.

Market Concentration

DASR market three pivotal supplier test results are provided in Table 10-36. Table 10-36 shows the percent of intervals with a day-ahead scheduling reserve market

75 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 121 (July 7, 2022).

76 See PJM. "PJM Manual 13: Emergency Operations," § 2.2 Reserve Requirements, Rev. 84 (Mar. 23, 2022).

77 PJM. "Energy and Reserve Pricing & Interchange Volatility Final Proposal Report," <http://www.pjm.com/~/media/committees-groups/committees/mrc/20141030/20141030-item-04-erpiv-final-proposal-report.ashx>.

78 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 11.2.1 Day-Ahead Scheduling Reserve Market Requirement, Rev. 121 (July 7, 2022).

79 See *id.*

80 See PJM. "PJM Manual 13: Emergency Operations," § 3.2 Conservative Operations, Rev. 85 (Oct. 1, 2022).

clearing price greater than $0.01 that failed the three pivotal supplier test. In the first nine months of 2022, on average, there were 85 testable intervals each month, of which 90.0 percent had at least one pivotal supplier. In total, there were 769 testable intervals, of which 603, or 78.4 percent, had at least one pivotal supplier.

Table 10-36 DASR market three pivotal supplier test results and number of hours with DASR MCP above $0.01: January 2021 through September 2022

Year	Month	Number of Hours DASR MCP > $0.01	Percent of Hours DASR MCP > $0.01 Pivotal
2021	Jan	15	100.0%
2021	Feb	26	100.0%
2021	Mar	23	100.0%
2021	Apr	93	98.9%
2021	May	79	87.3%
2021	Jun	151	78.1%
2021	Jul	148	95.9%
2021	Aug	153	84.3%
2021	Sep	131	86.3%
2021	Oct	171	98.8%
2021	Nov	140	98.6%
2021	Dec	33	100.0%
2021	Average	97	94.0%
2022	Jan	43	100.0%
2022	Feb	12	100.0%
2022	Mar	42	90.5%
2022	Apr	16	100.0%
2022	May	62	72.6%
2022	Jun	142	84.5%
2022	Jul	212	86.8%
2022	Aug	168	86.3%
2022	Sep	72	88.9%
2022	Average	85	90.0%

Market Conduct

PJM rules allowed any unit with reserve capability that could be converted into energy within 30 minutes to offer into the DASR market.[81] Units that did not offer have their offers set to $0.00 per MW during the day-ahead market clearing process.

Economic withholding was an issue in the DASR market. The marginal cost of providing DASR was zero. All offers greater than zero constituted economic withholding. In the first nine months of 2022, 43.7 percent of generation units offered DASR at a daily price above $0.00 per MW. In the first nine months of 2022, 16.9 percent of daily offers were above $5.00 per MW.

The MMU recommended that market solutions for the DASR market be based on opportunity cost only in order to eliminate economic withholding. This recommendation was adopted effective October 1, 2022, with the market changes for the new secondary reserve product.

Market Performance

In the first nine months of 2022, the DASR market cleared at a price above $0.00 per MW in 12.6 percent of all hours. The weighted average DASR price for all cleared hours was $0.35 per MW. The average cleared MW in all hours was 4,820.2 MW. The average cleared MW in all hours when the DASRMCP was above $0.00 was 6,321.3 MW. The highest DASR price in the first nine months of 2022 was $34.00 per MW for one hour on May 31.

The introduction of Adjusted Fixed Demand (AFD) on March 1, 2015, created a bifurcated market. Table 10-37 shows the use of AFD in previous years. Table 10-38 shows the use of AFD in the first nine months of 2022. In the first nine months of 2022, AFD hours were only used in the months of January, May, June, July, August, and September. The resulting differences in market clearing price, MW cleared, and charges to PJM load from use of AFD could be substantial, as seen in Table 10-40 Table 10-39 shows the differences in price and MW between AFD hours and non-AFD hours in the first nine months of 2022.

Table 10-37 Hours with Adjusted Fixed Demand (AFD) added to the normal DASR requirement: 2015 through 2021

Year	Number of Hours with AFD	Normal Requirement as Percent of Forecast Load
2015	367	5.9%
2016	522	5.7%
2017	336	5.5%
2018	598	5.3%
2019	447	5.3%
2020	430	5.1%
2021	516	5.5%

81 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 121 (July 7, 2022).

Table 10-38 Hours with Adjusted Fixed Demand (AFD) and average increase in DASR requirement: January through September, 2022

Year	Month	Number of Hours with AFD	Average Increase in Requirement
2022	Jan	16	15.2%
2022	Feb	0	NA
2022	Mar	0	NA
2022	Apr	0	NA
2022	May	63	65.1%
2022	Jun	67	74.4%
2022	Jul	214	26.3%
2022	Aug	163	30.8%
2022	Sep	24	20.0%
2022	Total	547	37.0%

Table 10-39 Impact of Adjusted Fixed Demand on DASR prices and demand: January through September, 2022

Metric	Number of Hours	Weighted Day-Ahead Scheduling Reserve Market Clearing Price (DASRMCP)	Average Hourly Total DASR MW
All hours	6,551	$0.35	4,626.5
All hours when DASRMCP > $0	827	$2.28	5,702.3
All hours when AFD used	547	$2.15	7,292.5

While the AFD rules allowed PJM operators substantial discretion to add to DASR demand for a variety of reasons, the rationale for each specific increase was not always clear. The MMU recommended that PJM Market Operations attach a reason code to every hour in which PJM operators added additional DASR MW above the default DASR hourly requirement. The addition of such a code would have made the reason explicit, increased transparency and facilitated analysis of the use of PJM's ability to add DASR MW. This recommendation was adopted effective October 1, 2022, with the market changes for the new secondary reserve product which eliminated DASR and AFD.

Comparing the Normal Hour column against the AFD Hour column for five metrics (Table 10-40) shows that the use of AFD for 574 hours in the first nine months of 2022 significantly increased the cost of DASR by increasing the DASR MW cleared. Table 10-40 shows the cost increase. The average DASR clearing price in the first nine months of 2022 was $0.77 per MW for hours when the clearing price was above $0.00 and $4.49 per MW during hours when adjusted fixed demand was invoked by PJM Dispatch.

Table 10-40 DASR market, regular hours vs. adjusted fixed demand hours with price greater than $0: January 2021 through September 2022

		Number of Hours DASRMCP > $0		Weighted DASRMCP		Average PJM Load MW		Hourly Average Cleared DASR MW		Average Hourly DASR Credits	
Year	Month	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour
2021	Jan	28	NA	$0.08	NA	106,153	NA	4,847	NA	$380	NA
2021	Feb	32	NA	$0.16	NA	108,947	NA	4,974	NA	$815	NA
2021	Mar	24	NA	$0.17	NA	92,014	NA	4,327	NA	$732	NA
2021	Apr	129	NA	$0.21	NA	83,962	NA	3,983	NA	$846	NA
2021	May	68	11	$0.60	$1.91	99,007	105,454	4,661	9,514	$2,785	$18,147
2021	Jun	83	77	$0.41	$4.55	115,654	118,494	5,170	8,973	$2,124	$40,839
2021	Jul	115	46	$0.44	$1.41	122,396	129,739	5,460	7,842	$2,424	$11,095
2021	Aug	110	83	$0.35	$3.85	121,022	133,350	5,399	7,869	$1,877	$30,312
2021	Sep	107	40	$0.58	$3.45	104,852	105,046	4,776	9,117	$2,769	$31,492
2021	Oct	222	NA	$0.50	NA	87,526	NA	4,335	NA	$2,159	NA
2021	Nov	228	NA	$0.30	NA	89,025	NA	4,208	NA	$1,258	NA
2021	Dec	41	NA	$0.26	NA	100,378	NA	4,544	NA	$1,188	NA
2021		1,187	257	$0.39	$3.51	99,647	122,653	4,633	8,460	$1,791	$29,689
2022	Jan	52	1	$0.29	$0.19	114,012	116,746	4,799	4,856	$1,407	$923
2022	Feb	13	NA	$0.31	NA	112,857	NA	4,542	NA	$1,390	NA
2022	Mar	42	NA	$0.49	NA	98,063	NA	4,368	NA	$2,124	NA
2022	Apr	22	NA	$0.18	NA	88,142	NA	3,818	NA	$681	NA
2022	May	45	31	$0.29	$8.26	97,273	113,745	4,196	9,418	$1,237	$77,802
2022	Jun	110	42	$1.55	$4.23	118,219	115,167	5,017	9,746	$7,764	$41,216
2022	Jul	132	89	$0.59	$3.10	119,220	131,062	5,006	7,333	$2,958	$22,748
2022	Aug	103	68	$0.73	$4.58	121,415	128,332	4,969	7,413	$3,609	$33,967
2022	Sep	69	8	$0.96	$2.09	108,371	110,701	4,584	5,915	$4,380	$12,334
2022		588	239	$0.77	$4.49	113,189	124,504	4,771	7,992	$3,690	$35,886

Table 10-41 shows total number of hours when a DASR market cleared at a price above $0 along with average load, cleared MW, additional MW under AFD, and total charges for the DASR market in January 2021 through September 2022.

Table 10-41 DASR market all hours of DASR market clearing price greater than $0: January 2021 through September 2022

Year	Month	Number of Hours DASRMCP > $0	Weighted DASR Market Clearing Price	Average Hourly RT Load MW	PJM Cleared DASR MW	PJM Cleared Additional DASR MW	Credits
2021	Jan	28	$0.08	106,153	135,710	0	$10,640
2021	Feb	32	$0.16	108,947	159,163	0	$26,076
2021	Mar	24	$0.17	92,014	103,839	0	$17,564
2021	Apr	129	$0.21	83,962	513,819	0	$109,108
2021	May	79	$0.92	99,905	421,593	53,470	$389,001
2021	Jun	160	$2.97	117,021	1,120,041	351,422	$3,320,941
2021	Jul	161	$0.80	124,494	988,574	97,972	$789,171
2021	Aug	193	$2.18	126,324	1,246,974	168,469	$2,722,344
2021	Sep	147	$1.78	104,905	875,744	150,928	$1,555,947
2021	Oct	222	$0.50	87,526	962,369	0	$479,311
2021	Nov	228	$0.30	89,025	959,331	0	$286,853
2021	Dec	41	$0.26	100,378	186,320	0	$48,719
2021	Total	1,444	$1.27	103,741	7,673,478	822,262	$9,755,675
2022	Jan	53	$0.29	114,063	254,387	1,089	$74,083
2022	Feb	13	$0.31	112,857	59,044	0	$18,065
2022	Mar	42	$0.49	98,063	183,452	0	$89,213
2022	Apr	22	$0.18	88,142	83,989	0	$14,973
2022	May	76	$5.13	103,992	480,783	148,406	$2,467,548
2022	Jun	152	$2.69	117,376	961,196	209,266	$2,585,054
2022	Jul	221	$1.84	123,989	1,313,439	178,880	$2,415,045
2022	Aug	171	$2.64	124,166	1,015,863	156,422	$2,681,484
2022	Sep	77	$1.10	108,613	363,635	10,696	$400,897
2022	Total	827	$2.28	116,459	4,715,788	704,759	$10,746,362

When the DASR requirement was increased by PJM dispatch, the reserve requirement frequently could not be met without redispatching online resources which significantly affected the price by creating an LOC.

Secondary Reserve Market

The secondary reserve market applies to the last three months of 2022.

Market Structure

Supply

The supply of 30 minute reserves includes all primary reserves plus any synchronized or offline reserves that can convert to energy in 30 minutes. Secondary reserves are the reserves that take more than 10 minutes to convert to energy, but less than 30 minutes. This includes the unloaded capacity of online generation that can be achieved according to the resource ramp rates in 10 to 30 minutes. It also includes offline resources that offer a time to start of less than 30 minutes.

As with other reserves, certain resource types, including nuclear, wind, and solar units, are by default excluded from providing secondary reserves. Secondary reserves do not include pre-emergency or emergency demand response resources, even if they offer to start in less than 30 minutes.

Demand

The 30 minute reserve requirement is equal to the greatest of 3,000 MW, the primary reserve requirement, and the largest active gas contingency, plus 190 MW.[82] The ORDC is structured the same as the synchronized and primary reserve ORDCs, with a price of $850 per MW up to the minimum reserve requirement and $300 per MW for the additional 190 extended reserve requirement.

Unlike synchronized and primary reserves, PJM does not model a 30 minute reserve requirement for the defined reserve subzone.[83] However, PJM has the option to define a subzone natural gas contingency reserve requirement using 30 minute reserves. PJM did not exercise this option in the last three months of 2022.

Market Concentration

Table 10-42 shows the average HHI of the secondary reserve market, including synchronized, nonsynchronized, and 30 minute reserves, and the percent of intervals for which the maximum market share is above 20 percent. In the last three months of 2022, the RTO Zone was unconcentrated in the day-ahead and real-time markets.

Table 10-42 PJM 30 minute reserve market HHI: October through December, 2022

Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%
RTO	RT	882	28.2%
RTO	DA	527	0.3%

Market Conduct

Hydroelectric resources, energy storage resources, and load response resources are able to specify offer amounts for secondary reserve. Other market participants have available MW calculated by PJM, based on their submitted energy offer parameters.[84] Online resources' secondary reserves are based on ramp rates and the lesser of the secondary reserve maximum or economic maximum parameters, as well as any scheduled synchronized reserve.[85] The use of the secondary reserve maximum output limit requires prior approval by PJM.[86] Offline resources' secondary reserves are based on the time to start, which is the start-up time plus notification time, and any scheduled nonsynchronized reserve.[87]

Market Performance

Figure 10-13 provides the prices for secondary reserves for the last three months of 2022. Prices were zero except during Elliott when the secondary reserve constraint was binding. During Elliott PJM may have cleared 30 minute offline reserves on resources that were not actually available when the constraint was binding, meaning that there would have been a shortage of secondary reserves if all outages were properly reported.

82 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3 Reserve Requirement Determination, Rev. 122 (Oct. 1, 2022).

83 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3.1 Locational Aspect of Reserves, Rev. 122 (Oct. 1, 2022).

84 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.3 Reserve Market Resource Offer Structure, Rev. 122 (Oct. 1, 2022).

85 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.5.1 Reserve Market Capability for Online Generation Resources, Rev. 122 (Oct. 1, 2022).

86 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.2.1 Communication for Reserve Capability Limitation, Rev. 122 (Oct. 1, 2022).

87 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.5.2 Reserve Market Capability for Offline Generation Resources, Rev. 122 (Oct. 1, 2022).

Figure 10-13 Secondary reserve prices: October through December, 2022

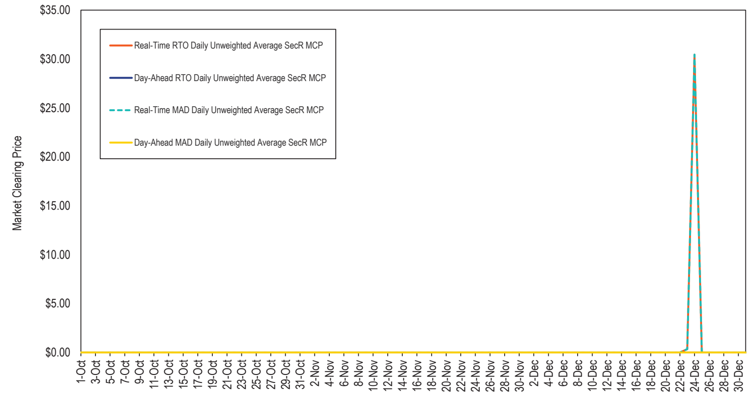


Table 10-43 shows the day-ahead credits, balancing market credits, LOC credits, and effective shortfall charges for secondary reserves in the last three months of 2022.[88] During Winter Storm Elliott, 30 minute reserve positions were converted to energy in real-time, resulting in negative balancing credits and offsetting LOC credits. In the last three months of 2022, amounts of secondary reserve shortfall all applied to intervals when the real-time secondary reserve market clearing price was $0 per MWh. Therefore, while there was shortfall in each of the last three months of 2022, the total effective shortfall charge for each month is $0 in Table 10-43.

Table 10-43 Monthly secondary reserve settlements: October through December, 2022

Year	Month	Total Day-Ahead Credits	Total Balancing MCP Credits	Total LOC Credits	Total Effective Shortfall Charge	Total Credits
2022	Oct	$0	$0	$61,173	$0	$61,173
2022	Nov	$0	$0	$10,667	$0	$10,667
2022	Dec	$0	($3,780,478)	$4,451,194	$0	$670,716

Table 10-44 provides secondary reserve credits by resource type for the last three months of 2022. Natural gas combustion turbines provided the most secondary reserves but had negative total credits due to resources being unavailable in real time during Winter Storm Elliott, either because they were on outage or because their reserve positions were converted to energy.

88 Unlike synchronized reserve, for secondary reserve, shortfall is accounted for in the balancing MCP credits and is not a separate item. The effective shortfall charge is the real-time SecR MCP multiplied by the shortfall MW, a value used when calculating the balancing MCP credits.

Table 10-44 Secondary reserve credits by resource type: October through December, 2022

Resource / Fuel Type	Day-Ahead MWh	Real-Time Capped MWh	Day-Ahead Credits	Balancing MCP Credits	LOC Credits	Total Credits
Combined Cycle	10,310	9,241	$0	($41,131)	$1,094,188	$1,053,057
Steam - Coal	1,902	5,019	$0	$34,461	$224,712	$259,173
RICE - Other	0	484	$0	$3,547	$74,831	$78,378
Hydro - Run of River	0	6,082	$0	$17,371	$49,465	$66,836
Hydro - Pumped Storage	5,212	1,339	$0	$8,518	$54,197	$62,715
Steam - Natural Gas	279	709	$0	$32,877	$10,374	$43,251
Steam - Oil	0	106	$0	$23,641	$62	$23,703
RICE - Oil	38,439	3,576	$0	$8,438	$8,604	$17,042
Steam - Other	8	35	$0	$20	$6,883	$6,903
RICE - Natural Gas	139,901	8,329	$0	$0	$6,567	$6,567
CT - Other	6,613	176	$0	$0	$0	$0
CT - Oil	1,657,849	279,415	$0	($454,669)	$296,584	($158,085)
CT - Natural Gas	18,438,567	2,706,727	$0	($3,413,552)	$2,696,569	($716,983)
Battery	0	0	NA	NA	NA	NA
DSR	0	0	NA	NA	NA	NA
Distributed Gen	0	0	NA	NA	NA	NA
Fuel Cell	0	0	NA	NA	NA	NA
Nuclear	0	0	NA	NA	NA	NA
Solar	0	0	NA	NA	NA	NA
Solar + Storage	0	0	NA	NA	NA	NA
Solar + Wind	0	0	NA	NA	NA	NA
Wind	0	0	NA	NA	NA	NA
Wind + Storage	0	0	NA	NA	NA	NA

Table 10-45 compares the dispatch-run and pricing-run market clearing prices for the day-ahead and real-time secondary reserve markets. In the last three months of 2022, the day-ahead price of secondary reserve was always $0 per MWh in both the pricing run and the dispatch run. The real-time secondary reserve market clearing price was above $0 per MWh in the pricing run and dispatch run on December 23 and December 24 during Winter Storm Elliot. It remained $0 per MWh outside of this event.

Table 10-45 Comparison of fast start and dispatch pricing components: October 2022 through December 2022

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2022	Oct	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2022	Nov	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2022	Dec	$0.00	$0.00	$0.00	0.0%	$0.48	$0.48	$0.01	1.2%

Regulation Market

Regulation matches generation with short term changes in load by moving the output of selected resources up and down via an automatic control signal. Regulation is provided by generators with a short-term response capability (less than five minutes) or by demand response (DR). The PJM Regulation Market is operated as a single real-time market.

Market Design

PJM's regulation market design is a result of Order No. 755.[89] The objective of PJM's regulation market design is to minimize the cost to provide regulation using two resource types in a single market.

The regulation market includes resources following two signals: RegA and RegD. Resources responding to either signal help control ACE (area control error). RegA is PJM's slow oscillation regulation signal and is designed for resources with the ability to sustain energy output for long periods of time, with slower ramp rates. RegD is PJM's fast oscillation regulation signal and is designed for resources with limited ability to sustain energy output and with faster ramp rates. Resources must qualify to follow one or both of the RegA and RegD signals, but will be assigned by the market clearing engine to follow only one signal in a given market hour.

The PJM regulation market design includes three clearing price components: capability ($/MW, based on the MW being offered); performance ($/mile, based on the total MW movement requested by the control signal, known as mileage); and lost opportunity cost ($/MW of lost revenue from the energy market as a result of providing regulation). The marginal benefit factor (MBF) and performance score translate a RegD resource's capability (actual) MW into marginal effective MW and offers into $/effective MW.

89 Order No. 755, 137 FERC ¶ 61,064 at P 2 (2011).

The regulation market solution is intended to meet the regulation requirement with the least cost combination of RegA and RegD. When solving for the least cost combination of RegA and RegD MW to meet the regulation requirement, the regulation market will substitute RegD MW for RegA MW when RegD is cheaper. Performance adjusted RegA MW are used as the common unit of measure, called effective MW, of regulation service. All resource MW (RegA and RegD) are converted into effective MW. RegA MW are converted into effective MW by multiplying the RegA MW offered by their performance score. RegD MW are converted into effective MW by multiplying the RegD offered by their performance score and by the MBF. The regulation requirement is defined as the total effective MW required to provide a defined amount of area control error (ACE) control.

The regulation market converts performance adjusted RegD MW into effective MW using the MBF in the PJM design. The MBF is used to convert incremental additions of RegD MW into incremental effective MW. The total effective MW for a given amount of RegD MW equal the area under the MBF curve (the sum of the incremental effective MW contributions). RegA and RegD resources should be paid the same price per effective MW.

The marginal rate of technical substitution (MRTS) is the marginal measure of substitutability of RegD resources for RegA resources in satisfying a defined regulation requirement at feasible combinations of RegA and RegD MW. While resources following RegA and RegD can both provide regulation service in PJM's Regulation Market, PJM's joint optimization is intended to determine and assign the optimal mix of RegA and RegD MW to meet the hourly regulation requirement. The optimal mix is a function of the relative effectiveness and cost of available RegA and RegD resources.

At any valid combination of RegA and RegD, regulation offers are converted to dollars per effective MW using the RegD offer and the MBF associated with that combination of RegA and RegD. The marginal contribution of a RegD MW to effective MW is equal to the MRTS associated with that RegA/RegD combination.

For example, a 1.0 MW RegD resource with a total offer price of $2 per MW with a MBF of 0.5 and a performance score of 100 percent would be calculated as offering 0.5 effective MW (0.5 MBF times 1.00 performance score times 1 MW). The total offer price would be $4 per effective MW ($2 per MW offer divided by the 0.5 effective MW).

Regulation performance scores (0.0 to 1.0) measure the response of a regulating resource to its assigned regulation signal (RegA or RegD) every 10 seconds by measuring: delay, the time delay of the regulation response to a change in the regulation signal; correlation, the correlation between the regulating resource output and the regulation signal; and precision, the difference between the regulation response and the regulation requested.[90] Performance scores are reported on an hourly basis for each resource.

Table 10-46 and Figure 10-14 show the average performance score by resource type and the signal followed in 2022. In these figures, the MW used are actual MW and the performance score is the hourly performance score of the regulation resource.[91] Each category (color bar) is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-14 shows, 73.2 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 20.6 percent of RegA resources had average performance scores within that range in 2022. In 2021, 76.0 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 25.0 percent of RegA resources had average performance scores within that range.

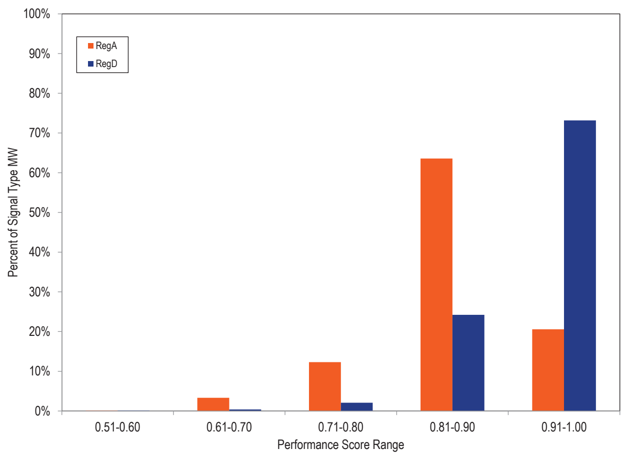
Table 10-46 Hourly average performance score by unit type: 2022

		Performance Score Range				
		51-60	61-70	71-80	81-90	91-100
RegA	Battery	-	-	-	-	-
	CT	0.0%	0.0%	2.0%	61.9%	36.1%
	Diesel	0.0%	0.0%	0.0%	19.0%	81.0%
	DSR	0.0%	0.0%	100.0%	0.0%	0.0%
	Hydro	0.0%	0.0%	0.1%	56.1%	43.8%
	Steam	0.2%	4.7%	17.1%	66.7%	11.2%
RegD	Battery	0.2%	0.0%	0.1%	22.8%	77.0%
	CT	0.0%	0.0%	12.0%	66.7%	21.4%
	Diesel	0.0%	0.0%	4.1%	52.1%	43.8%
	DSR	0.0%	0.1%	16.9%	28.3%	54.7%
	Hydro	0.0%	15.8%	0.0%	35.1%	49.2%
	Steam	-	-	-	-	-

90 PJM "Manual 12: Balancing Operations," § 4.5.6 Performance Score Calculation, Rev. 47 (Oct. 1, 2022).

91 Except where explicitly referred to as effective MW or effective regulation MW, MW means actual MW unadjusted for either MBF or performance factor.

Figure 10-14 Hourly average performance score by regulation signal type: 2022



Each cleared resource in a class (RegA or RegD) is allocated a portion of the class signal (RegA or RegD). This portion of the class signal is based on the cleared regulation MW of the resource relative to the cleared MW for that class. This signal is called the Total Regulation Signal (TREG) for the resource. A resource with 10 MW of capability will be provided a TREG signal asking for a positive or negative regulation movement between negative and positive 10 MW around its regulation set point.

Resources are paid Regulation Market Clearing Price (RMCP) credits and lost opportunity cost credits, which are uplift payments. If a resource's lost opportunity costs for an hour are greater than its RMCP credits, that resource receives lost opportunity cost credits equal to the difference. PJM posts clearing prices for the regulation market (RMCCP, RMPCP and RMCP) in dollars per effective MW. The regulation market clearing price (RMCP in $/effective MW) for the hour is the simple average of the 12 five minute RMCPs within the hour. The RMCP is set in each five minute interval based on the marginal offer in each interval. The performance clearing price (RMPCP in $/effective MW) is based on the marginal performance offer (RMPCP) for the hour. The capability clearing price (RMCCP in $/effective MW) is equal to the difference between the RMCP for the hour and the RMPCP for the hour. This is done so the total of RMPCP plus RMCCP equals the total clearing price (RMCP) but the RMPCP is maximized.

Market solution software relevant to regulation consists of the Ancillary Services Optimizer (ASO) solving hourly; the intermediate term security constrained economic dispatch market solution (IT SCED) solving every 15 minutes; and the real-time security constrained economic dispatch market solution (RT SCED) solving approximately every five minutes. The market clearing price is determined by pricing software (LPC) that looks at the units cleared in the most recently approved RT SCED case, approximately 10 minutes ahead of the target solution time. The marginal prices assigned by the LPC to five minute intervals are averaged over the hour for an hourly regulation market clearing price.

Market Design Issues

PJM's current regulation market design is severely flawed and is not efficient or competitive. The market results do not represent the least cost solution for the defined level of regulation service.

In a well functioning market, every resource should be paid the same clearing price per unit produced. That is not true in the PJM Regulation Market. RegA and RegD resources are not paid the same clearing price in dollars per effective MW. RegD resources are being paid more than the market clearing price. This flaw in the market design has caused operational issues, has caused over investment in RegD resources.

If all MW of regulation were treated the same in both the clearing of the market and in settlements, many of the issues in the PJM Regulation Market would be resolved. However, the current PJM rules result in the payment to RegD resources being up to 1,000 times the correct price.

RegA and RegD have different physical capabilities. In order to permit RegA and RegD to compete in the single PJM Regulation Market, RegD must be translated into the same units as RegA. One MW of RegA is one effective MW. The translation is done using the marginal benefit factor (MBF). As more RegD is added to the market, the relative value of RegD declines, based on its actual performance attributes. For example, if the MBF is 0.001, a MW of RegD is worth 0.001 MW of RegA (or 1/1,000 of a MW of RegA). This is the same thing as saying that 1.0 MW of RegD is equal to 0.001 effective MW when the MBF is 0.001.

Almost all of the issues in PJM's Regulation Market are caused by the inconsistent application of the MBF. Because the MBF is not included in settlements, when the MBF is less than 1.0, RegD resources are paid too much. When the MBF is less than 1.0, each MW of RegD is worth less than 1.0 MW of RegA. The market design buys the correct amount of RegD, but pays RegD as if the MBF were 1.0. In an extreme case, when the MBF is 0.001, RegD MW are paid 1,000 times too much. If the market clearing price is $1.00 per MW of RegA, RegD is paid $1,000 per effective MW. Resolution of this problem requires that PJM pay RegD for the same effective MW it provides in regulation, 0.001 MW.

To address the identified market flaws, the MMU and PJM developed a joint proposal which was approved by the PJM Members Committee on July 27, 2017, and filed with FERC on October 17, 2017. The PJM/MMU joint proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market. FERC rejected the proposal finding it inconsistent with Order No. 755.

The MBF related issues with the regulation market have been raised in the PJM stakeholder process. In 2015, PJM stakeholders approved an interim, partial solution to the RegD over procurement problem which was implemented on December 14, 2015. The interim solution was designed to reduce the relative value of RegD MW in all hours and to cap purchases of RegD MW during critical performance hours. But the interim solution did not address the fundamental issues in the optimization or the lack of consistency in the application of the MBF.

Additional changes were implemented on January 9, 2017. These modifications included changing the definition of off peak and on peak hours, adjusting the currently independent RegA and RegD signals to be interdependent, and changing the 15 minute neutrality requirement of the RegD signal to a 30 minute neutrality requirement.

The January 9, 2017, design changes appear to have been intended to make RegD more valuable. That is not a reasonable design goal. The design goal should be to determine the least cost way to provide needed regulation. The RegA signal is now slower than it was previously, which may make RegA following resources less useful as ACE control. RegA is now explicitly used to support the conditional energy neutrality of RegD. The RegD signal is now the difference between ACE and RegA. RegA is required to offset RegD when RegD moves in the opposite direction of that required by ACE control in order to permit RegD to recharge. These changes in the signal design will allow PJM to accommodate more RegD in its market solutions. The new signal design is not making the most efficient use of RegA and RegD resources. The explicit reliance on RegA to offset issues with RegD is a significant conceptual change to the design that is inconsistent with the long term design goal for regulation. PJM increased the regulation requirement as part of these changes.

The January 9, 2017, design changes replaced off peak and on peak hours with nonramp and ramp hours with definitions that vary by season. The regulation requirement for ramp hours was increased from 700 MW to 800 MW (Table 10-47). These market changes still do not address the fundamental issues in the optimization or the lack of consistency in the application of the MBF.

Table 10-47 Seasonal regulation requirement definitions[92]

Season	Dates	Nonramp Hours	Ramp Hours
Winter	Dec 1 - Feb 28(29)	00:00 - 03:59 09:00 - 15:59	04:00 - 08:59 16:00 - 23:59
Spring	Mar 1 - May 31	00:00 - 04:59 08:00 - 16:59	05:00 - 07:59 17:00 - 23:59
Summer	Jun 1 - Aug 31	00:00 - 04:59 14:00 - 17:59	05:00 - 13:59 18:00 - 23:59
Fall	Sep 1 - Nov 30	00:00 - 04:59 08:00 - 16:59	05:00 - 07:59 17:00 - 23:59

Performance Scores

Performance scores, by class and unit, are not an indicator of how well resources contribute to ACE control. Performance scores are an indicator only of how well the resources follow their TREG signal. High performance scores with poor signal design are not a meaningful measure of performance. For example, if ACE indicates the need for more regulation but RegD resources have provided all their available energy, the RegD regulation signal will be in the opposite direction of what is needed to control ACE. So, despite moving in the wrong direction for ACE control, RegD resources would get a good performance score for following the RegD signal and will be paid for moving in the wrong direction.

92 See PJM. "Regulation Requirement Definition," <http://www.pjm.com/~/media/markets-ops/ancillary/regulation-requirement-definition.ashx>.

The RegD signal prior to January 9, 2017, is an example of a signal that resulted in high performance scores, but due to 15 minute energy neutrality built into the signal, ran counter to ACE control at times. Energy neutrality means that energy produced equals energy used within a defined timeframe. With 15 minute energy neutrality, if a battery were following the regulation signal to provide MWh for 7.5 minutes, it would have to consume the same amount of MWh for the next 7.5 minutes. When neutrality correction of the RegD signal is triggered, it overrides ACE control in favor of achieving zero net energy over the 15 minute period. When this occurs, the RegD signal runs counter to the control of ACE and hurts rather than helps ACE. In that situation, the control of ACE, which must also offset the negative impacts of RegD, depends entirely on RegA resources following the RegA signal. High performance scores under the signal design prior to January 9, 2017, was not an indication of good ACE control.

The January 9, 2017, design changes did not address the fundamental issues with the definition of performance or the nature of payments for performance in the regulation market design. The regulation signal should not be designed to favor a particular technology. The signal should be designed to result in the lowest cost of regulation to the market. Only with a performance score based on full substitutability among resource types should payments be based on following the signal. The MRTS must be redesigned to reflect the actual capabilities of technologies to provide regulation. The PJM regulation market design remains fundamentally flawed.

In addition, the absence of a performance penalty, imposed as a reduction in performance score and/or as a forfeiture of revenues, for deselection initiated by the resource owner within the hour, creates a possible gaming opportunity for resources which may overstate their capability to follow the regulation signal. The MMU recommends that there be a penalty enforced as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour, to prevent gaming.

Battery Settlement

The change from 15 to 30 minute signal neutrality, implemented in the January 9, 2017, design changes, resulted in the reduction of performance scores for short duration batteries. In April 2017 several participants filed a complaint against PJM, asserting that these changes discriminated against their battery units.[93] The MMU objected to the complaints. Despite the unsupported assertions in the complaint, PJM settled with the participants. The settlement was approved by FERC on April 7, 2020.[94] Table 10-48 shows the battery units that are part of the settlement. Starting July 1, 2020, the affected battery units began receiving compensation based on the greater of their current performance score, or their rolling average actual hourly performance score for the last 100 hours the resource operated prior to the January 9, 2017, implementation of the 30-minute conditional neutrality. The additional regulation credits received in 2022 as a result of the settlement are shown in Table 10-49.

Table 10-48 Batteries in settlement

Parent Company	Unit	MW
The AES Corporation	Laurel Mountain	32.0
	Warrior Run	10.0
Energy Capital Partners, LLC	Hazel	20.0
Galt Power, Inc.	Trent	4.0
	McHenry	20.0
	Beckjord 1	2.0
	Beckjord 2	2.0
Invenergy, LLC	Beech Ridge	31.5
	Grand Ridge 6	4.5
	Grand Ridge 7	31.5
NextEra Energy, Inc.	Lee Dekalb	20.0
	Garrett	10.4
	Meyersdale	18.0
	Mantua Creek	2.0
Renewable Energy Systems Holdings, LTD	Joliet	20.0
	West Chicago	20.0
Sumitomo Corporation	Willey	6.0

Table 10-49 Excess regulation credits received by settlement batteries: January through December, 2022

Month	Excess Regulation Credit ($)
Jan	$230,764
Feb	$84,963
Mar	$70,375
Apr	$128,896
May	$104,817
Jun	$179,703
Jul	$160,327
Aug	$216,929
Sep	$169,958
Oct	$143,995
Nov	$85,026
Dec	$659,729
Total	$2,235,481

93 See FERC Docket Nos. EL17-64-000 and EL17-65-000.
94 See 170 FERC ¶ 61,258 (2020).

In addition to paying uneconomic regulation credits based on inflated performance scores, the settlement also requires that the affected battery units be cleared in the regulation market regardless of whether their offer was economic. As long as the settlement batteries are offered as either self scheduled with a zero offer, or as a zero priced offer, they must be cleared despite the fact that these units would not necessarily have cleared based on economics.[95] In order to comply with this condition, PJM clears additional MW beyond what is needed for the regulation requirement in cases where the settlement battery units did not clear but met the offer rules of the settlement. This results in excess charges to customers for regulation service. Table 10-50 shows the impact of clearing additional MW beyond what is needed for the regulation requirement, as a result of the battery settlement, in 2022. Other changes in market dynamics starting in the third quarter of 2021 reduced the impact of this settlement rule because most of the settlement units clear based on economics. In 2022, the battery settlement resulted in customers paying $110,230 more than needed, in order to compensate the additional MW from settlement batteries that would not have otherwise cleared. As a result of the battery settlement, PJM customers in 2022 over paid for regulation by $2.3 million (the sum of Table 10-49 and Table 10-50).

Table 10-50 Excess payments and monthly additional MW cleared due to battery settlement: January through December, 2022.

	Battery Settlement Impact	
Month	Regulation Credits	Additional Cleared Regulation MW
Jan	$3,576	54.5
Feb	$9,974	384.3
Mar	$43,880	833.3
Apr	$829	24.7
May	$4,056	78.9
Jun	$904	33.5
Jul	$10,454	240.9
Aug	$10,487	234.9
Sep	$13,474	182.8
Oct	$5,539	133.1
Nov	$1,014	83.1
Dec	$6,043	105.2
Total	$110,230	2,389.1

Regulation Signal

As with any signal design for substitutable resources, the MBF function should be determined by the ability of RegA and RegD resources to follow their signals, including conditions under which neutrality cannot be maintained by RegD resources. The ability of energy limited RegD to provide ACE control depends on the availability of excess RegA capability to support RegD under the conditional neutrality design. When RegD resources are largely energy limited resources, a correctly calculated MBF would exhibit a rapid decrease in the MBF value for every MW of RegD added. The result is that only a small amount of energy limited RegD is economic. The current and proposed signals and corresponding MBF functions do not reflect these principles or the actual substitutability of resource types.

Marginal Benefit Factor Issues

The MBF function, as implemented in the PJM Regulation Market, is not equal to the MRTS between RegA and RegD. The MBF is not consistently applied throughout the market design, from optimization to settlement, and market clearing does not confirm that the resulting combinations of RegA and RegD are realistic and can meet the defined regulation demand. The calculation of total regulation cleared using the MBF is incorrect.[96]

The result has been that the PJM Regulation Market has over procured RegD relative to RegA in most hours, has provided a consistently inefficient market signal to participants regarding the value of RegD in every hour, and has overpaid for RegD. This over procurement has degraded the ability of PJM to control ACE in some hours while at the same time increasing the cost of regulation. When the price paid for RegD is above the level defined by an accurate MBF function, there is an artificial incentive for inefficient entry of RegD resources.

PJM and the MMU filed a joint proposal with FERC on October 17, 2017, to address issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market, but the proposal was rejected by FERC.[97]

Marginal Benefit Factor Not Correctly Defined

The MBF used in the PJM Regulation Market prior to the December 14, 2015, changes did not accurately reflect the MRTS between RegA and RegD resources under the old market design, and it does not accurately reflect the MRTS between RegA and RegD resources under the current design. The MBF function is incorrectly

95 See *id.* at P 17.

96 The MBF, as used in this report, refers to PJM's incorrectly calculated MBF and not the MBF equivalent to the MRTS.

97 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

defined and improperly implemented in the current PJM Regulation Market.

The MBF should be the marginal rate of technical substitution between RegA and RegD MW at different, feasible combinations of RegA and RegD that can be used to provide a defined level of regulation service. The objective of the market design is to find, given the relative costs of RegA and RegD MW, the least cost feasible combination of RegA and RegD MW. If the MBF function is incorrectly defined, or improperly implemented in the market clearing and settlement, the resulting combinations of RegA and RegD will not represent the least cost solution and may not be a feasible way to reach the target level of regulation.

The MBF is not included in PJM's settlement process. This is a design flaw that results in incorrect payments for regulation. The issue results from two FERC orders. From October 1, 2012, through October 31, 2013, PJM implemented a FERC order that required the MBF to be fixed at 1.0 for settlement calculations only. On October 2, 2013, FERC directed PJM to eliminate the use of the MBF entirely from settlement calculations of the capability and performance credits and replace it with the RegD to RegA mileage ratio in the performance credit paid to RegD resources, effective retroactively to October 1, 2012.[98] That rule continues in effect. The result of the current FERC order is that the MBF is used in market clearing to determine the relative value of an additional MW of RegD, but the MBF is not used in the settlement for RegD.

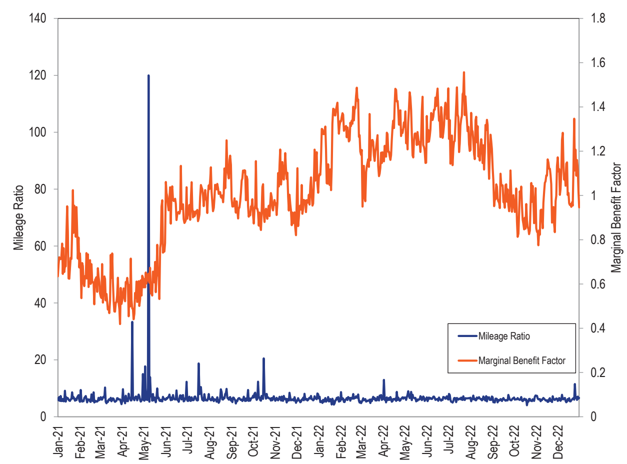
If the MBF were consistently applied, every resource would receive the same clearing price per marginal effective MW. But the MBF is not consistently applied and resources do not receive the same clearing price per marginal effective MW.

The change in design decreased RegA mileage (the change in MW output in response to regulation signal per MW of capability), increased the proportion of cleared RegD resources' capability that was called by the RegD signal (increased REG for a given MW) to better match offered capability, increased the mileage required of RegD resources and changed the energy neutrality component of the signal from a strict 15 minute neutrality to a conditional 30 minute neutrality. The changes in signal design increased the mileage ratio (the ratio of RegD mileage to RegA mileage). In addition, to adapt to the 30 minute neutrality requirement, some RegD resources decreased their offered capability to maintain their performance.

Figure 10-15 shows the daily average MBF and the mileage ratio. The weighted average mileage ratio decreased from 6.95 in 2021, to 6.23 in 2022 (a decrease of 10.4 percent). The average MBF increased from 0.84 in 2021, to 1.18 in 2022 (an increase of 40.3 percent). The high mileage ratios are the result of the mechanics of the mileage ratio calculation. Extreme mileage ratios result when the RegA signal is fixed at a single value (pegged) to control ACE and the RegD signal is not. If RegA is held at a constant MW output, mileage is zero for RegA. The result of a fixed RegA signal is that RegA mileage is very small and therefore the mileage ratio is very large.

These results are an example of why it is not appropriate to use the mileage ratio, rather than the MBF, to measure the relative value of RegA and RegD resources. In these events, RegA resources are providing ACE control by providing a fixed level of MW output which means zero mileage, while RegD resources alternate between helping and hurting ACE control, both of which result in positive mileage.

Figure 10-15 Daily average MBF and mileage ratio: January 2021 through December 2022



The increase in the average mileage ratio caused by the signal design changes introduced on January 9, 2017, caused a large increase in payments to RegD resources on a performance adjusted MW basis.

98 145 FERC ¶ 61,011 (2013).

Table 10-51 shows RegD resource payments on a performance adjusted actual MW basis and RegA resource payments on a performance adjusted MW basis by month, from January 1, 2021, through December 30, 2022. The average regulation market clearing price in 2022 was $27.52 higher than in 2021 (See Table 10-65.) In 2022, RegD resources earned 21.5 percent more per performance adjusted actual MW than RegA resources (20.7 percent in 2021) due to the inclusion of the mileage ratio in RegD MW settlement.

Table 10-51 Average monthly price paid per performance adjusted actual MW of RegD and RegA: January 2021 through December 2022

		Settlement Payments		
Year	Month	RegD ($/Performance Adjusted MW)	RegA ($/Performance Adjusted MW)	Percent RegD Overpayment ($/Performance Adjusted MW)
2021	Jan	$14.29	$11.43	25.1%
	Feb	$23.87	$19.90	19.9%
	Mar	$20.81	$17.93	16.0%
	Apr	$20.86	$16.73	24.6%
	May	$20.22	$16.42	23.2%
	Jun	$23.01	$18.40	25.1%
	Jul	$24.09	$19.34	24.6%
	Aug	$37.86	$31.77	19.2%
	Sep	$34.62	$28.59	21.1%
	Oct	$46.15	$38.91	18.6%
	Nov	$61.59	$52.92	16.4%
	Dec	$33.56	$26.85	25.0%
Yearly		$30.08	$24.93	20.7%
2022	Jan	$74.63	$68.59	8.8%
	Feb	$39.28	$31.51	24.6%
	Mar	$33.90	$25.56	32.6%
	Apr	$60.31	$49.00	23.1%
	May	$49.81	$41.57	19.8%
	Jun	$63.28	$54.47	16.2%
	Jul	$60.45	$53.40	13.2%
	Aug	$71.87	$63.64	12.9%
	Sep	$55.22	$46.90	17.7%
	Oct	$44.84	$36.33	23.4%
	Nov	$27.32	$22.41	21.9%
	Dec	$122.69	$117.10	4.8%
Yearly		$58.87	$48.46	21.5%

The current settlement process does not result in paying RegA and RegD resources the same price per effective MW. RegA resources are paid on the basis of dollars per effective MW of RegA. RegD resources are not paid in terms of dollars per effective MW of RegA because the MBF is not used in settlements. Instead of being paid based on the MBF, (RMCCP + RMPCP)*MBF, RegD resources are paid based on the mileage ratio (RMCCP + (RMPCP*mileage ratio)). Because the RMCCP component makes up the majority of the overall clearing price, when the MBF is above one, RegD resources can be underpaid on a per effective MW basis by the current payment method, unless offset by a high mileage ratio. When the MBF is less than one, RegD resources are overpaid on a per effective MW basis, unless offset by a low mileage ratio. The average MBF was greater than 1.0 in 2022 (1.18).

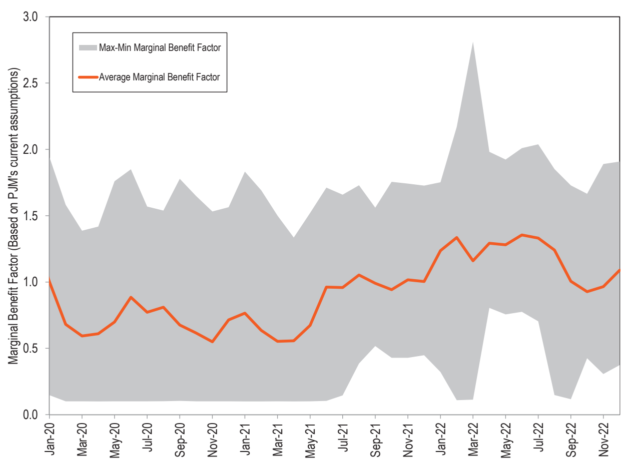
The effect of using the mileage ratio instead of the MBF for purposes of settlement is illustrated in Table 10-52. Table 10-52 shows how much RegD resources are currently being paid, adjusted to a per effective MW basis, on average, in 2021 and 2022 under the current rules, compared to how much RegD resources should have been paid if they were actually paid for effective MW. Using the MBF consistently throughout the PJM regulation market would result in RegA and RegD resources being paid exactly the same on a per effective MW basis. However, the PJM regulation market only uses the MBF in the market clearing and setting of price on a dollar per effective MW basis, it does not use the MBF to convert RegD MW into effective MW for purposes of settlement. Because the MBF is not used to convert RegD MW into effective MW for purposes settlement, RegD resources are paid the dollar per effective MW price, but this is paid for performance adjusted MW, not for effective MW. This causes the MW value of RegD resources to be inflated in settlement when the MBF is less than one and to be undervalued in settlement when the MBF is greater than one. In 2022, the MBF averaged 1.18, while the average daily mileage ratio was 6.23, resulting in RegD resources being paid $8.0 million less than they would have been paid on an effective MW basis if the MBF were correctly implemented. In 2021, the MBF averaged 0.84, and the average mileage ratio was 6.95, resulting in RegD resources being paid $8.9 million more than they would have been paid if the MBF were correctly implemented. The shift from overpayment to underpayment of RegD resources between 2021 and 2022 is the result of an incorrect calculation of the MBF, as a result of the way dual offers are handled by PJM. This error has led to a decrease in the amount of RegD cleared and a resulting increase in the MBF of RegD resources. The higher MBF values have not been accurately reflected in settlement.

Table 10-52 Average monthly price paid per effective MW of RegD and RegA under mileage and MBF based settlement: January 2021 through December 2022

		RegD Settlement Payments				
Year	Month	Mileage Based RegD ($/Effective MW)	Marginal Rate of Technical Substitution Based RegD ($/Effective MW)	RegA ($/Effective MW)	Percent RegD Overpayment ($/Effective MW)	Total RegD Overpayment ($)
2021	Jan	$30.47	$11.43	$11.43	166.6%	$558,397
	Feb	$88.91	$19.90	$19.90	346.7%	$1,310,279
	Mar	$61.03	$17.93	$17.93	240.4%	$1,277,850
	Apr	$65.99	$16.73	$16.73	294.3%	$1,492,094
	May	$39.55	$16.42	$16.42	140.9%	$1,081,445
	Jun	$26.57	$18.40	$18.40	44.4%	$457,543
	Jul	$27.36	$19.34	$19.34	41.5%	$513,073
	Aug	$38.23	$31.77	$31.77	20.4%	$288,112
	Sep	$35.63	$28.59	$28.59	24.6%	$410,694
	Oct	$51.13	$38.91	$38.91	31.4%	$688,515
	Nov	$63.20	$52.92	$52.92	19.4%	$377,458
	Dec	$33.94	$26.85	$26.85	26.4%	$399,675
Yearly		$46.48	$24.93	$24.93	86.4%	$8,855,253
2022	Jan	$62.73	$68.59	$68.59	(8.5%)	($1,580,376)
	Feb	$29.38	$31.51	$31.51	(6.8%)	($516,687)
	Mar	$31.86	$25.56	$25.56	24.7%	$281,052
	Apr	$46.90	$49.00	$49.00	(4.3%)	($550,585)
	May	$39.30	$41.57	$41.57	(5.4%)	($582,040)
	Jun	$47.78	$54.47	$54.47	(12.3%)	($1,133,591)
	Jul	$45.45	$53.40	$53.40	(14.9%)	($1,438,918)
	Aug	$60.51	$63.64	$63.64	(4.9%)	($1,069,872)
	Sep	$55.46	$46.90	$46.90	18.2%	$239,007
	Oct	$50.03	$36.33	$36.33	37.7%	$916,419
	Nov	$31.77	$22.41	$22.41	41.8%	$514,986
	Dec	$104.29	$117.10	$117.10	(10.9%)	($3,113,242)
Yearly		$50.68	$51.12	$48.46	(0.8%)	($8,033,848)

Figure 10-16 shows, the monthly maximum, minimum and average MBF, for January 2020 through December 2022. The average daily MBF in the 2022 was 1.18. The average daily MBF in 2021 was 0.84. The bottom of the MBF range results from PJM's administratively defined MBF minimum threshold of 0.1. The large increase in the maximum and average MBF is due to an incorrect calculation of the MBF, as a result of the way dual offers are handled by PJM. This error has led to a decrease in the amount of RegD cleared, and an increase in the MBF.

Figure 10-16 Maximum, minimum, and average PJM calculated MBF by month: January 2020 through December 2022



The MMU recommends that the regulation market be modified to incorporate a consistent and correct application of the MBF throughout the optimization, assignment and settlement process.[99]

The overpayment of RegD has resulted in offers from RegD resources that are almost all at an effective cost of $0.00 ($0.00 offers plus self scheduled offers). RegD MW providers are ensured that such offers will clear and will be paid a price determined by the offers of RegA resources. This is evidence of the impact of the flaws in the clearing engine and the overpayment of RegD resources on the offer behavior of RegD resources.

Table 10-53 shows, by month, cleared RegD MW with an effective price of $0.00 (units with zero offers plus self scheduled units) for January 2021 through December 2022. In 2022, an average of 96.5 percent of all RegD MW clearing the market had an effective offer of $0.00. In 2021, an average of 98.7 percent of all cleared RegD MW had an effective cost of $0.00. In 2022, an average of 59.2 percent of all RegD offers were self scheduled, compared to an average of 71.9 percent of all RegD offers in 2021.

The high percentage of self scheduled offers is a result of the incentives created by the flaws in the regulation market. Because self scheduled offers are price takers, they are cleared along with the zero cost offers in the market clearing engine. However, unlike zero cost offers, self scheduled offers do not risk having an LOC added to their offer during the market clearing process, ensuring that self scheduled offers have a zero cost during market clearing. Given the increasing saturation of the regulation market with RegD MW, specifically demand response and battery units which do not receive LOC, market participants eligible for LOC that offer at zero instead of self scheduling, run the risk of an LOC added to their offer, and thus not clearing the market.

The average monthly RegD cleared in the market decreased 26.8 MW (14.6 percent), from 183.5 MW in 2021 to 156.8 MW in 2022. The average monthly RegD cleared with an effective cost of zero decreased 29.8 MW (16.5 percent), from 181.1 MW in 2021 to 151.3 MW in 2022. Self scheduled RegD cleared MW decreased 39.2 MW (29.7 percent), from 131.9 MW in 2021 to 92.7 MW in 2022. Average cleared RegD MW with a zero cost offer increased 9.4 MW (19.1 percent), from 49.2 MW in 2021 to 58.6 MW in 2022. The incorrect way that dual offers are offered and cleared in the regulation market has led to the decrease in the average monthly RegD cleared and the increase in the average monthly MBF seen in Figure 10-16.

99 See "Regulation Market Review," Operating Committee (May 5, 2015) <http://www.pjm.com/~/media/committees-groups/committees/oc/20150505/20150505-item-17-regulation-market-review.ashx>.

Table 10-53 Average cleared RegD MW and average cleared RegD with an effective price of $0.00 by month: January 2021 through December 2022

		Average Performance Adjusted Cleared RegD MW						
Year	Month	$0.00 Offer	$0.00 Offer Percent of Total	Self Scheduled	Self Scheduled Percentage of Total	Total Effective Cost of Zero	Effective Cost of Zero Percentage of Total	Total
2021	Jan	49.6	26.1%	139.9	73.7%	189.6	99.9%	189.8
	Feb	52.4	25.6%	152.3	74.4%	204.7	100.0%	204.7
	Mar	47.2	23.3%	155.4	76.7%	202.6	100.0%	202.6
	Apr	48.6	24.0%	154.0	76.0%	202.7	100.0%	202.7
	May	47.5	24.8%	143.8	75.0%	191.3	99.9%	191.6
	Jun	45.8	25.2%	133.3	73.4%	179.2	98.6%	181.7
	Jul	48.4	26.4%	130.7	71.4%	179.1	97.8%	183.1
	Aug	49.9	28.4%	120.8	68.6%	170.8	97.0%	176.0
	Sep	50.8	30.6%	111.1	67.1%	161.8	97.7%	165.6
	Oct	50.6	30.2%	114.6	68.3%	165.3	98.5%	167.7
	Nov	50.2	30.6%	109.0	66.5%	159.2	97.1%	164.0
	Dec	49.4	28.6%	118.0	68.2%	167.5	96.8%	173.0
Yearly		49.2	26.8%	131.8	71.9%	181.0	98.7%	183.4
2022	Jan	51.8	33.8%	95.5	62.2%	147.4	96.0%	153.5
	Feb	59.6	40.6%	84.1	57.2%	143.8	97.8%	147.0
	Mar	59.7	38.2%	93.3	59.7%	153.0	98.0%	156.2
	Apr	52.9	36.8%	84.3	58.5%	137.2	95.3%	144.0
	May	52.5	37.0%	85.7	60.4%	138.1	97.4%	141.8
	Jun	51.6	34.1%	89.2	59.0%	140.8	93.1%	151.2
	Jul	59.9	38.4%	84.9	54.4%	144.8	92.8%	156.1
	Aug	62.1	38.6%	92.2	57.3%	154.4	95.9%	160.9
	Sep	65.2	39.6%	95.2	57.9%	160.5	97.5%	164.6
	Oct	66.6	38.5%	100.8	58.3%	167.4	96.7%	173.1
	Nov	65.1	39.1%	99.3	59.6%	164.4	98.8%	166.4
	Dec	56.5	33.9%	107.9	64.8%	164.4	98.8%	166.4
Yearly		58.6	37.4%	92.8	59.2%	151.4	96.5%	156.8

Incorrect MBF and total effective MW when clearing units with dual product offers

Under PJM market rules, regulation units that have the capability to provide both RegA and RegD MW are permitted to submit an offer for both signal types in the same market hour. While the objective of the PJM market design is to find the least cost combination of RegA and RegD resources to provide the required level of regulation service, the method of clearing the regulation market for an hour in which one or more units has a dual offer is incorrect and leads to solutions that are not the most economic. The result of the flaw is that the MBF in the regulation market clearing phase is incorrectly low compared to the MBF in the market solution phase, too little RegD is cleared relative to the efficient amount, the RegD resources that do clear are underpaid when the resulting MBF is greater than 1.0 and the actual amount of effective MW procured is higher than the regulation requirement.

In order for the clearing engine to provide the correct economic solution when the pool of available resources contains one or more units with dual offers, the calculation would have to be performed iteratively to determine which of the dual offers would provide the least cost solution. But this is not how PJM clears the regulation market when there are dual offer units. PJM rank orders the regulation supply curve by potential effective cost assuming the dual offer resources are available as both RegA and RegD resources simultaneously, and assigns every RegD resource, including dual offer resources, a unit specific benefit factor.

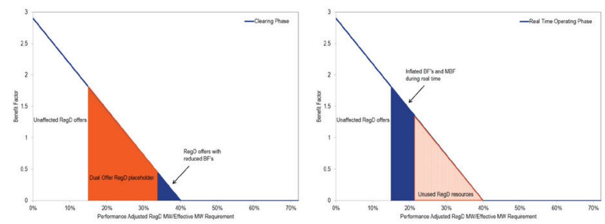
Each dual offer resource is assigned to run as either a RegD or RegA resource based on which of the two offers has a lower effective cost. But PJM does not redefine the supply curve using appropriately recalculated unit specific benefit factors for the remaining RegD resources prior to clearing the market.

During the clearing phase, the MBF of RegD resources is a function of the RegD MW that clear. The MBF for all RegD resources declines as more RegD resources are cleared. Based on this relationship, in the case where a dual offer unit is assigned to be a RegA resource rather than a RegD resource, the MBF of remaining RegD resources in the supply curve should increase. The placeholder RegD MW from the dual offer should be removed, the cleared MW from below the placeholder should be shifted up the supply/MBF curve, and additional RegD MW offers that were pushed below an MBF of zero and initially not included, should be considered. But PJM does not recalculate the MBF values for the remaining RegD resources when determining the cleared effective MW needed to satisfy the regulation requirement during the clearing phase. The result is that the MBF in the clearing phase is incorrectly low, and the actual amount of effective MW procured is higher.

After meeting the target effective MW to satisfy the regulation requirement for that hour through the clearing process, the unit specific benefit factors of those displaced units are recalculated in the real-time operating phase and increased based on their actual contribution. The effective MW contributions of those originally displaced units are correctly calculated in the operating phase, but because the supply for that hour has already been set based on their incorrect effective MW, the solution includes more effective MW than calculated in the clearing phase. As a result, the market solution includes more than the target level of effective MW in the actual operating hour.

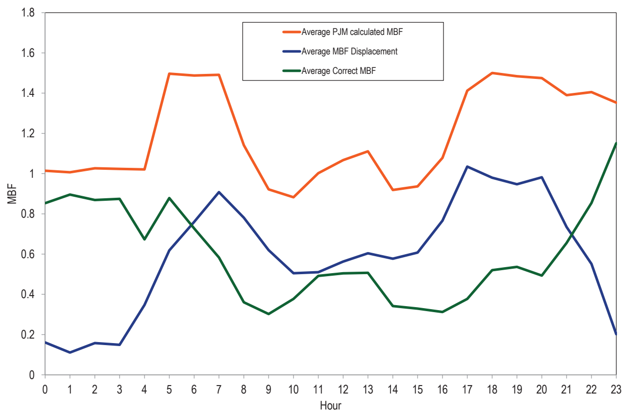
The issue is illustrated in Figure 10-17. The example shows a clearing phase and a real time operating phase. In this example, a 150 MW unit offers both RegA and RegD. The 150 MW unit's position in the RegD effective cost curve and the potential effective MW are represented as the orange area under the curve in the clearing phase. The effective MW of the cleared RegD resources with higher effective costs are represented by the blue triangle in the clearing phase. Not shown are additional RegD MW with higher effective costs that were assigned an MBF of 0 and not cleared. The 150 MW dual offer unit is chosen to operate as a RegA resource in the operational hour. As a result, the cleared supply for RegA in the clearing phase is the same RegA supply realized in the real time operating phase. But that is not the case for the RegD supply. Since the supply curve and unit specific benefit factors of RegD MW are not recalculated in the clearing phase after the 150 MW RegD offer is removed, the amount of effective MW realized in the real-time operating phase is inconsistent with the clearing phase. Because the RegD portion of the 150 MW dual offer unit was not chosen to be RegD MW, the RegD resources represented by the blue triangle in the clearing phase will contribute more effective MW (the blue area in the real-time solution phase) in the real-time solution phase than was assumed in the clearing phase because the MBF in the clearing phase was too low. Since the blue area under the curve in the real-time solution phase is greater than the blue area in the clearing phase and the amount of RegA remains the same between the clearing phase and real-time operating phase, the market will have cleared too many effective MW relative to the effective MW requirement. The MBF in the operating phase is higher than if the clearing had been solved correctly.

Figure 10-17 Clearing phase BF/effective MW reduction, real-time BF/effective MW inflation, and exclusion of available RegD resources



In 2022, all hours had at least one unit with a dual offer. In 2022, 40.7 percent of all hours had at least one dual offer unit that was chosen to run as RegA, resulting in an average MBF increase of 0.75 in the operating phase. The average MBF increase due to dual offers clearing as RegA in 2021 was 0.48. This indicates that the amount of MW clearing as RegA from dual offers has increased, and the amount of RegD clearing has been artificially reduced, resulting in higher MBF of RegD in the market solution in 2022. In 2022, 8,874 dual offers from generating units were cleared as RegA, an increase of 55.8 percent from 2021 (5,694 dual offers clearing as RegA). If the market had been cleared correctly, the correct average MBF would have been significantly lower in real time (operating phase), because additional RegD offers with lower benefit factors that were initially excluded, would have been included after the removal of the dual offer placeholder, reducing the MBF. Figure 10-18 illustrates the PJM calculated average MBF in real time (operating phase), the average amount the MBF is artificially increased (MBF displacement) due to dual offers clearing as RegA, and what the correct average MBF would have been in each hour of the day for 2022 if the clearing solution were solved correctly.

Figure 10-18 Effect of PJM's current dual offer clearing method on the average MBF in each hour of the day: 2022



Absent the ability to correctly clear dual offers, the MMU recommends that the ability of resources to submit dual offers be removed. Under this revision to the rules, resources could offer as either RegA or RegD in a given hour, but not both within the same market hour.

Price Spikes

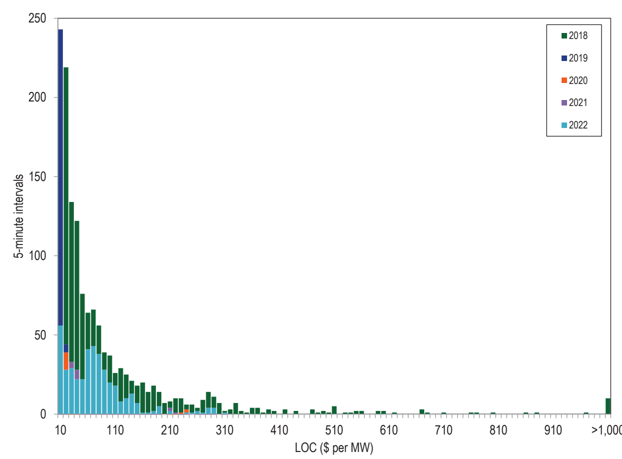
Beginning in 2018, extreme price spikes were identified in the regulation market. The price spikes were caused by a combination of the inconsistent application of the MBF in the market design and the discrepancy between the hour ahead estimated LOC and the actual realized within hour LOC.

The regulation market is cleared on an hour ahead basis, using offers that are adjusted by dividing each component of an offer (capability, performance, and lost opportunity cost) by the product of the unit specific benefit factor and unit specific performance score. To calculate the hour ahead estimate of the adjusted LOC offer component, hour ahead projections of LMPs are used. Units are then cleared based on the sum of each of their hour ahead adjusted offer components. The actual LOC is used to determine the final, actual interval specific all in offer of RegD resources.

In some cases the estimated LOC is very low or zero but the actual within hour LOC is a positive number. In instances where the MBF of the within hour marginal unit is less than one (e.g. the marginal unit is a RegD unit), this discrepancy in the estimated and realized LOC will cause a large discrepancy between the expected offer price (as low as $0/MW) and the realized offer price of the resource in the actual market result. This will cause a significant price spike in the regulation market. In cases where the MBF of the marginal resource is very low, such as 0.001, the price spikes can be very significant for a small change between expected and actual LOC. In January 2019, FERC approved PJM's proposal to create a 0.1 floor for the MBF to reduce the occurrence of these price spikes.[100] This change reduced the amount and frequency of the price spikes, but it was not designed to eliminate them and it did not eliminate them.

Figure 10-19 shows the LOC in each five minute interval in which the marginal unit had a unit specific benefit factor less than one (e.g. a RegD unit) and the LOC was greater than zero from 2018 through 2022.

Figure 10-19 LOC distribution in each five minute interval with a RegD marginal unit and an LOC greater than zero: 2018 through 2022



For a RegD resource to clear the regulation market with an MBF of 0.001, the resource's offer, in dollars per marginal effective MW, must be less than or equal to competing offers from RegA MW. A RegD offer of 1 MW with an MBF of 0.001 and a price of $1 per MW, would provide 0.001 effective MW at a price of $1,000 per effective MW. So long as RegA MW are available for less than $1,000 per effective MW, this resource will not clear. The only way for RegD MW to clear to the point where the MBF of the last MW is 0.001, is if the offer price of the relevant resources that clear, including estimated LOC, is $0.00. But, if the same resource(s) has a positive LOC within the hour, based on real-time changes in LMP, the zero priced offer is adjusted to reflect the positive LOC, resulting in an extremely high offer and clearing price for regulation.

100 See 166 FERC ¶ 61,040 (2019).

While an incorrect estimate of a potential LOC can result in an extremely high price, the resulting regulation market prices are mathematically correct for the price of each effective MW. The prices in every interval reflect the marginal costs of regulation given the resources dispatched and accurately reflect the marginal offer of minimally effective resources which had unexpectedly high LOC components of their within hour offers. But, due to the current market design's failure to use the MBF in settlement, RegD is not paid on a dollar per effective MW basis. This disconnect between the process of setting price and the process of paying resources is the primary source of the market failure in PJM's Regulation Market and the cause of the observed price spikes in the regulation market. In the example, the 0.001 MW from the RegD resource should be paid $1,000 times 0.001 MW or $1.00. But the current rules would pay the RegD resource $1,000 times 1.0 MW or $1,000. If the market clearing and the settlements rules were consistent, the incentive for this behavior would be eliminated. The current rules provide a strong incentive for this behavior.

The prices spikes observed in PJM's Regulation Market are a symptom of a market failure in PJM's Regulation Market caused by an inconsistent application of the MBF between market clearing and market settlement. Due to the inconsistent application of the MBF, the current market results are not consistent with a competitive market outcome. In any market, resources should be paid the marginal clearing price for their marginal contribution. In the regulation market, all resources should be paid the marginal clearing price per effective MW and all resources in the regulation market should be paid for each of their effective MW. PJM's Regulation Market does not do this. PJM's market applies the MBF in determining the relative and total value of RegD MW in the market solution for purposes of market clearing and price, but does not apply the same logic in determining the payment of RegD for purposes of settlement. As a result, market prices do not align with payment for contributions to regulation service in market settlements.

The inconsistent application of the MBF in PJM's regulation market design is generating perverse incentives and perverse market results. The price spikes are a symptom of the problem, not the problem itself.

Uplift Calculation Issues

Regulation uplift is calculated by comparing a resource's regulation offer price plus its regulation lost opportunity cost (including shoulder LOC if applicable) adjusted by the performance score, to the clearing price credits the unit received.[101] If the sum of the resource's offer plus LOC is greater than the amount of clearing price credits received, additional uplift credits are given equal to the difference.

The calculation of regulation uplift during settlements for coal and natural gas units is incorrect, and results in the overpayment of uplift.[102] In order to determine the amount of regulation uplift, the difference between the MW output of the unit while it was providing regulation is compared to the desired MW output of the unit if it had not provided regulation. The desired MW output at LMP used in the calculation of regulation uplift during settlements is determined based on a unit's energy offer and the LMP during the interval being evaluated. But this desired MW does not account for the ability of a unit to actually produce the desired output because it ignores the fact that units have a limited physical ability ramp. It does not take into account the ramp rate. This results in the overpayment of uplift by paying for MW that the unit could not have produced given their energy market output at the beginning of the interval and their ramp rate.

Table 10-54 shows the amount of uplift overpayment by fuel type for 2022, as a result of the ramp rate not being used in the current calculation. The overpayments are calculated using a desired MW level that can be achieved in a five minute market interval based on the units' ramp rates. In 2022, overpayments totaled $28.9 million. Coal units received 42.1 percent of the overpayment while providing 4.9 percent of settled regulation MW.

The MMU recommends that the ramp rate limited desired MW output be used in the regulation uplift calculation, to reflect the physical limits of the unit's ability to ramp and to eliminate overpayment for opportunity costs when the payment uses an unachievable MW.

101 The clearing price for each interval is set by the marginal unit's total offer (capability and performance offers plus LOC), adjusted by the marginal unit's performance score, and does not include any shoulder LOC.

102 Hydro units operate on a schedule rather than an energy bid, therefore a different equation is used to calculate their regulation LOC and uplift. The issue discussed does not effect that calculation. Also, demand response and battery units do not receive uplift.

Table 10-54 Amount of LOC overpayment: January 2021 through December 2022

		Uplift overpayment		
Year	Month	Coal	Natural Gas	Total
2021	Jan	$189,413	$151,479	$340,892
	Feb	$362,280	$458,780	$821,059
	Mar	$213,908	$313,696	$527,604
	Apr	$409,813	$527,769	$937,582
	May	$384,659	$175,792	$560,451
	Jun	$387,173	$231,534	$618,707
	Jul	$152,339	$180,229	$332,568
	Aug	$135,911	$360,753	$496,664
	Sep	$217,114	$516,718	$733,833
	Oct	$137,579	$741,654	$879,233
	Nov	$926,402	$2,365,660	$3,292,061
	Dec	$327,458	$945,934	$1,273,392
Total		$3,844,048	$6,969,998	$10,814,046
2022	Jan	$1,959,942	$2,308,232	$4,268,174
	Feb	$432,077	$1,103,635	$1,535,711
	Mar	$297,947	$990,141	$1,288,088
	Apr	$1,447,659	$1,627,371	$3,075,030
	May	$625,195	$1,318,174	$1,943,369
	Jun	$752,995	$1,529,581	$2,282,575
	Jul	$2,816,672	$1,359,550	$4,176,222
	Aug	$1,945,760	$1,772,383	$3,718,143
	Sep	$409,138	$973,280	$1,382,418
	Oct	$749,413	$1,217,687	$1,967,100
	Nov	$335,976	$567,153	$903,129
	Dec	$383,864	$6,817	$2,356,842
Total		$12,156,637	$14,774,004	$28,896,802

Winter Storm Elliott

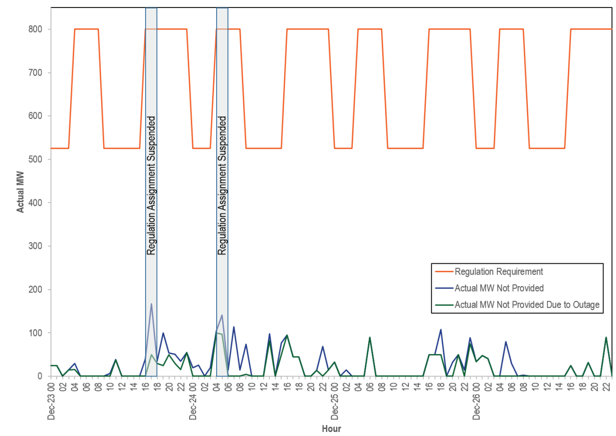
During emergency events, PJM has the authority to suspend all regulation assignments.[103] During such suspensions and for ten minutes after the end of the event, performance scores for regulating resources are not calculated.[104] PJM suspended regulation assignments during the evening peak on December 23, 2022, and on the morning of December 24, 2022.

During Elliott, PJM did not have enough MW available to clear and satisfy the regulation requirement of 800 MW for three hours on December 24, 2022 (0600-0800). The average hourly regulation requirement shortfall was 118.3 MW.

In addition, multiple units were committed for regulation in the hour ahead clearing, but did not provide regulation in real time. Figure 20 shows the amount of regulation actual MW that were committed, but did not provide regulation in real time, and the committed MW that did not provide regulation due to an outage. An hourly average of 26.7 MW were committed but did not provide regulation from December 23 through December 26. Of the average shortfall, an average of 16.5 MW was the result of unit outages.

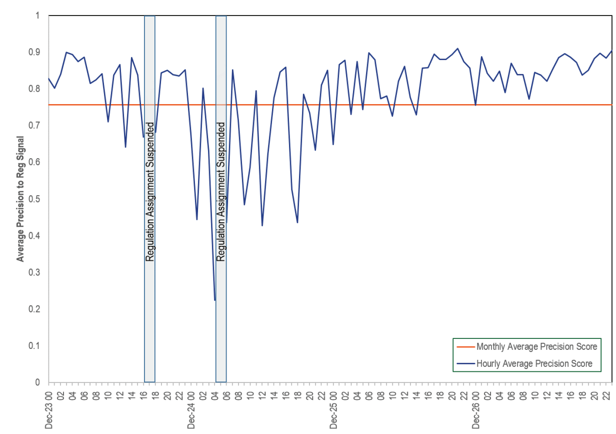
103 See "PJM Manual 13: Emergency Operations," § 2.3.2, Rev. 86 (Nov. 03, 2022).
104 See "PJM Manual 12: Balancing Operations," § 4.4.8, Rev. 47 (Oct. 01, 2022).

Figure 10-20 Committed regulation actual MW that dropped out of real time.



Some battery units that provided regulation in this period were not able to sustain the output called for by PJM. Figure 21 shows the average hourly precision score of all battery units in operation, from December 23 through December 26, as well as the monthly average precision score of all battery units for December 2022.[105]

Figure 10-21 Average hourly and monthly precision score of battery units to RegD signal



105 Flaws in the current performance score calculations allow two of the three components to remain high, even when the unit is performing poorly, or not at all. The precision component of the unit's response to the regulation signal is the best indicator of actual performance.

Market Structure

Supply

Table 10-55 shows average hourly offered MW (actual and effective), and average hourly cleared MW (actual and effective) for all hours in 2022.[106] Actual MW are adjusted by the historic 100-hour moving average performance score to get performance adjusted MW, and by the resource specific benefit factor to get effective MW. A resource can choose to follow either signal. For that reason, the sum of each signal type's capability can exceed the full regulation capability. Offered MW are calculated based on the offers from units that are designated as available for the day. These are daily offers that can be modified on an hourly basis up to 65 minutes before the hour.[107] Eligible MW are calculated from the hourly offers from units with daily offers and units that are offered as unavailable for the day, but still offer MW into some hours. Units with daily offers are permitted to offer above or below their daily offer from hour to hour. As a result of these hourly MW adjustments, the average hourly Eligible MW can be higher than the Offered MW.

In 2022, the average hourly offered supply of regulation for nonramp hours was 746.7 actual MW (756.4 effective MW). This was an increase of 5.9 actual MW (an increase of 11.5 effective MW) from 2021, when the average hourly offered supply of regulation was 740.8 actual MW (744.9 effective MW). In 2022, the average hourly offered supply of regulation for ramp hours was 1,101.6 actual MW (1,110.3 effective MW). This was an increase of 35.3 actual MW (an increase of 15.4 effective MW) from 2021, when the average hourly offered supply of regulation was 1,066.4 actual MW (1,094.9 effective MW).[108]

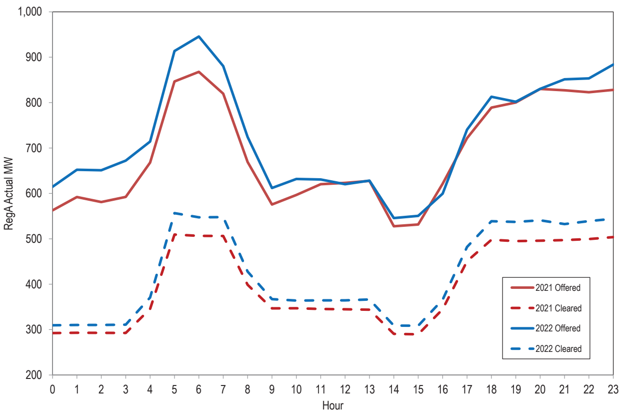
The ratio of the average hourly offered supply of regulation to average hourly regulation demand (actual cleared MW) for nonramp hours was 1.60 in 2022 (1.54 in 2021). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (actual cleared MW) for ramp hours was 1.54 in 2022 (1.51 in 2021).

Table 10-55 Hourly average actual and effective MW offered and cleared: 2022[109]

			By Resource Type		By Signal Type	
		All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Actual Offered MW	Ramp	1,101.6	1,080.5	21.1	869.2	232.4
	Nonramp	746.7	730.4	16.2	577.6	169.1
Effective Offered MW	Ramp	1,110.3	1,080.2	30.1	744.9	365.4
	Nonramp	756.4	738.4	18.1	492.6	263.9
Actual Cleared MW	Ramp	715.1	694.1	21.1	543.3	171.9
	Nonramp	465.3	449.4	15.9	308.1	157.2
Effective Cleared MW	Ramp	799.9	769.8	30.0	469.6	330.3
	Nonramp	525.2	507.4	17.8	265.7	259.5

The average hourly offered and cleared actual MW from RegA resources are shown in Figure 10-22. The average hourly offered MW from RegA resources during ramp hours for 2022 was 869.2 actual MW, an increase of 4.8 percent from 2021 (829.6 actual MW.) The average hourly offered MW from RegA resources during nonramp hours for 2022 was 577.6 actual MW, an increase of 5.3 percent from 2021 (548.5 actual MW). The average hourly cleared MW from RegA resources during ramp hours for 2022 was 543.3 actual MW, an increase of 8.1 percent from 2021 (502.5 actual MW). The average hourly cleared MW from RegA resources during nonramp hours for 2022 was 308.1 actual MW, an increase of 5.7 percent from 2021 (291.4 actual MW).

Figure 10-22 Average hourly RegA actual MW offered and cleared: 2021 through 2022[110]



106 Unless otherwise noted, analysis provided in this section uses PJM market data based on PJM's internal calculations of effective MW values, based on PJM's currently incorrect MBF curve. The MMU is working with PJM to correct the MBF curve.

107 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.2 Regulation Market Eligibility, Rev. 122 (Oct. 1, 2022).

108 Effective MW equal actual MW multiplied by the performance score and benefit factor for each unit. In the case of RegA, the benefit factor is always equal to one, and performance scores are always less than one, so effective MW of RegA are less than actual MW. For RegD resources effective MW can be larger than actual MW, if the benefit factor is greater than one. When adding RegA and RegD total MW together, actual MW can be larger or smaller than effective MW, depending on the influence of RegA MW and RegD MW.

109 PJM operations treats some nonramp hours as ramp hours, with a regulation requirement of 800 MW rather than 525 MW. All ramp/nonramp analysis performed is based on the requirement used in each hour rather than the definitions given in Table 10-2. A ramp hour occurring during what is normally a nonramp period is treated as a ramp hour.

110 Offered MW includes MW from units that are dual offering as both RegA and RegD.

The average hourly offered MW from RegD resources during ramp hours for 2022 was 232.4 actual MW, a decrease of 1.8 percent from 2021 (236.8 actual MW). (Figure 10-23) The average hourly offered MW from RegD resources during nonramp hours for 2022 was 169.1 actual MW, a decrease of 12.0 percent from 2021 (192.2 actual MW) (Figure 10-23). The average hourly cleared MW from RegD resources during ramp hours for 2022 was 171.9 actual MW, a decrease of 15.9 percent from 2021 (204.4 actual MW). The average hourly cleared MW from RegD resources during nonramp hours for 2022 was 157.2 actual MW, a decrease of 17.4 percent from 2021 (190.2 actual MW).

Figure 10-23 Average hourly RegD actual MW offered and cleared: 2021 through 2022[111]

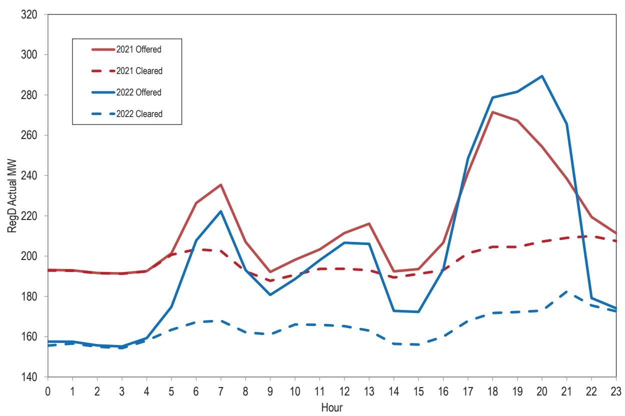


Table 10-57 provides the settled regulation MW by source unit type, the total settled regulation MW provided by all resources, the percent of settled regulation provided by unit type, and the clearing price, uplift, and total regulation credits. In Table 10-57 the MW have been adjusted by the performance score since this adjustment forms the basis of payment for units providing regulation. Total regulation performance adjusted settled MW decreased 2.7 percent from 4,596,353.2 MW in 2021 to 4,471,303.7 MW in 2022. The average proportion of regulation provided by natural gas units increased the most, by 6.9 percent from 2021 to 2022. Battery units had the largest decrease in average proportion of regulation provided, decreasing 7.8 percent, from 2021 to 2022. The total regulation credits in 2022 were $293,361,721, an increase of 104.7 percent from $143,337,707 in 2021. The increase in regulation credits is due, in part, to a higher LOC component of regulation prices as a result of higher energy prices in 2022 compared to 2021.

When a resource offers into the regulation market, an estimated regulation LOC is added by PJM to form a total offer (units self scheduled or not providing in the energy market have a regulation LOC of zero). After a unit clears, the actual five minute interval LMP is used to calculate each unit's regulation LOC, update their total offers, and determine a marginal unit/clearing price in each five minute interval. This within hour calculation of total offers, including LOC, uses each cleared resource's rolling 100 hour average performance score. During settlements, each unit's regulation LOC and total offers are recalculated using each unit's within hour actual performance score. This recalculated LOC and offer using the actual within hour performance score is not used to recalculate the within hour clearing price. This means that the clearing price for the hour will not equal the correct clearing price. Where the resulting market price is lower than an individual resource offer adjusted for the within hour performance score, the resource is paid uplift to make up the difference.

The top ten units that received the most uplift in 2022 are shown in Table 10-56.

111 Offered MW includes MW from units that are dual offering as both RegA and RegD.

Table 10-56 Top 10 recipients of regulation uplift credits: 2022

Rank	Parent Company	Unit Name	Fuel Type	Total Regulation Uplift Credit	Share of Total Regulation Uplift Credits
1	Dominion Energy Inc	VP BATH COUNTY 1-6 H	HYDRO	$3,596,484	8.5%
2	Constellation Energy Generation LLC	PE MUDDY RUN 1-8 H	HYDRO	$2,550,202	6.0%
3	American Electric Power Company Inc	AEP MOUNTAINEER 1 F	COAL	$2,399,749	5.7%
4	American Electric Power Company Inc	AEP MITCHELL - KAMMER 1 F	COAL	$1,782,302	4.2%
5	American Electric Power Company Inc	AEP AMOS 1 F	COAL	$1,217,607	2.9%
6	Ontario Power Generation Inc	AP LKLYN 1-4 H	HYDRO	$1,156,105	2.7%
7	American Municipal Power Inc	FE FREMONT ENERGY CENTER 3 CC	NATURAL GAS	$1,111,968	2.6%
8	American Electric Power Company Inc	AEP MITCHELL - KAMMER 2 F	COAL	$1,087,453	2.6%
9	American Electric Power Company Inc	AEP BIG SANDY 1 F	NATURAL GAS	$1,083,635	2.6%
10	Arclight Capital Holdings LLC	PS LINDEN 2 CC	NATURAL GAS	$1,048,658	2.5%
Total of Top 10				$17,034,164	40.3%
Total Regulation Uplift Credits				$42,281,047	100.0%

The uplift credits received for each unit type are shown in Table 10-57. The total uplift credits received increased 181.0 percent from $15,047,831 in 2021 to $42,281,047 in 2022. This increase, like the increase in total credits, is due in part to higher LOC components of regulation prices and offers as a result of higher energy prices in 2022 compared to 2021. Coal units had the largest increase in uplift payments, increasing from $3,939,892 (26.2 percent of total uplift) in 2021, to $13,625,655 (32.2 percent of total uplift) in 2022.

Table 10-57 PJM regulation by source: 2021 and 2022[112]

Year	Source	Number of Units	Performance Adjusted Settled Regulation (MW)	Percent of Settled Regulation	Clearing Price Credits	Uplift Credits	Total Regulation Credits
2021	Battery	23	1,538,257	33.5%	$45,184,072	$0	$45,184,072
	Coal	19	329,515	7.2%	$7,182,900	$3,939,892	$11,122,792
	Hydro	28	813,584	17.7%	$22,497,027	$3,253,703	$25,750,729
	Natural Gas	186	1,866,425	40.6%	$52,112,081	$7,854,236	$59,966,317
	DR	19	48,572	1.1%	$1,313,796	$0	$1,313,796
Total		275	4,596,353.2	100.0%	$128,289,877	$15,047,831	$143,337,707
2022	Battery	21	1,149,044	25.7%	$67,657,550	$0	$67,657,550
	Coal	21	218,050	4.9%	$15,153,709	$13,625,655	$28,779,364
	Hydro	28	885,317	19.8%	$52,849,244	$8,878,730	$61,727,974
	Natural Gas	152	2,122,501	47.5%	$109,705,839	$19,776,662	$129,482,501
	DR	21	96,392	2.2%	$5,714,333	$0	$5,714,333
Total		243	4,471,303.7	100.0%	$251,080,675	$42,281,047	$293,361,721

Significant flaws in the regulation market design have led to an over procurement of RegD MW primarily in the form of storage capacity. The incorrect market signals have contributed to more storage projects entering PJM's interconnection queue, despite clear evidence that the market design is flawed and despite operational evidence that the RegD market is saturated (Table 10-58).

Table 10-58 Active battery storage projects by submitted year: 2014 through 2022

Year	Number of Storage Projects	Total Capacity (MW)
2014	1	10.0
2015	4	41.0
2016	0	0.0
2017	1	2.0
2018	14	600.1
2019	55	3,609.4
2020	152	9,457.9
2021	310	23,782.1
2022	136	15,433.5
Total	673	52,936.0

112 Biomass data have been added to the natural gas category for confidentiality purposes.

The supply of regulation can be affected by regulating units retiring from service. If all units that are requesting retirement through 2022 retire, the supply of regulation in PJM will be reduced by less than one percent.

Demand

The demand for regulation does not change with price. The regulation requirement is set by PJM to meet NERC control standards, based on reliability objectives, which means that a significant amount of judgment is exercised by PJM in determining the actual demand. Prior to October 1, 2012, the regulation requirement was 1.0 percent of the forecast peak load for on peak hours and 1.0 percent of the forecast valley load for off peak hours. Between October 1, 2012, and December 31, 2012, PJM changed the regulation requirement several times. It had been scheduled to be reduced from 1.0 percent of peak load forecast to 0.9 percent on October 1, 2012, but instead it was changed from 1.0 percent of peak load forecast to 0.78 percent of peak load forecast. It was further reduced to 0.74 percent of peak load forecast on November 22, 2012 and reduced again to 0.70 percent of peak load forecast on December 18, 2012. On December 14, 2013, it was reduced to 700 effective MW during peak hours and 525 effective MW during off peak hours. The regulation requirement remained 700 effective MW during peak hours and 525 effective MW during off peak hours until January 9, 2017. A change to the regulation requirement was approved by the RMISTF in 2016, with an implementation date of January 9, 2017. The regulation requirement was increased from 700 effective MW to 800 effective MW during ramp hours (Table 10-47).

Table 10-59 shows the average hourly required regulation by month and the ratio of supply to demand for both actual and effective MW, for ramp and nonramp hours. The average hourly required regulation by month is an average of the ramp and nonramp hours in the month. Changes in the actual MW required to satisfy the regulation requirement are the result of the amount of RegD actual MW cleared. When more RegD MW are cleared, the MBF is lower, resulting in those actual MW being worth less effective MW, requiring more actual MW to satisfy the requirement. When MBFs are higher, the actual MW of RegD are worth more effective MW, reducing the amount of actual MW needed to satisfy the requirement.

The nonramp regulation requirement of 525.0 effective MW was provided by a combination of cleared RegA and RegD resources equal to 465.0 hourly average performance adjusted actual MW in 2022. This is a decrease of 16.6 performance adjusted actual MW from 2021, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 481.6 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of cleared RegA and RegD resources equal to 715.0 hourly average performance adjusted actual MW in 2022. This is an increase of 7.6 performance adjusted actual MW from 2021, where the average hourly regulation cleared MW for ramp hours were 707.3 performance adjusted actual MW.[113]

113 The supply of performance adjusted MW is less than the demand because the regulation requirement is based on effective MW. Effective MW are performance adjusted MW multiplied by the MBF, and the average MBF in 2022 was 1.18.

Table 10-59 Required regulation and ratio of supply to requirement: January 2021 through December 2022

Hours	Month	Average Required Regulation (MW) 2021	Average Required Regulation (MW) 2022	Average Required Regulation (Effective MW) 2021	Average Required Regulation (Effective MW) 2022	Ratio of Supply MW to MW Requirement 2021	Ratio of Supply MW to MW Requirement 2022	Ratio of Supply Effective MW to Effective MW Requirement 2021	Ratio of Supply Effective MW to Effective MW Requirement 2022
Ramp	Jan	713.2	720.6	800.0	800.0	1.59	1.51	1.42	1.37
	Feb	709.7	729.4	800.0	800.0	1.53	1.71	1.37	1.52
	Mar	713.8	723.0	800.0	800.0	1.54	1.54	1.38	1.39
	Apr	702.8	729.3	800.0	800.0	1.48	1.47	1.33	1.34
	May	705.5	720.2	800.0	800.0	1.45	1.54	1.32	1.38
	Jun	698.8	714.4	799.9	800.0	1.50	1.60	1.36	1.44
	Jul	699.0	720.3	799.9	800.0	1.54	1.55	1.38	1.40
	Aug	707.4	710.9	800.0	800.0	1.58	1.60	1.43	1.43
	Sep	710.7	704.3	800.0	800.0	1.47	1.53	1.35	1.38
	Oct	712.9	703.3	799.9	800.0	1.44	1.45	1.32	1.32
	Nov	708.4	698.8	800.0	800.0	1.41	1.43	1.30	1.29
	Dec	705.7	705.2	799.9	798.5	1.51	1.49	1.38	1.33
Nonramp	Jan	495.1	467.4	525.2	525.0	1.52	1.62	1.42	1.45
	Feb	500.4	466.9	525.1	525.0	1.59	1.78	1.47	1.56
	Mar	495.9	468.8	525.2	525.1	1.59	1.63	1.47	1.46
	Apr	490.9	469.1	525.1	525.1	1.51	1.56	1.41	1.41
	May	487.1	461.5	525.5	525.3	1.54	1.60	1.43	1.43
	Jun	478.6	459.6	525.4	525.8	1.50	1.66	1.39	1.48
	Jul	475.5	459.9	525.1	525.1	1.51	1.64	1.40	1.47
	Aug	474.4	461.3	525.2	525.3	1.60	1.65	1.47	1.48
	Sep	470.9	465.0	525.1	525.2	1.58	1.59	1.44	1.43
	Oct	471.8	468.0	525.1	525.1	1.51	1.59	1.39	1.43
	Nov	468.8	463.5	525.0	525.5	1.45	1.52	1.34	1.38
	Dec	469.5	468.6	525.0	525.1	1.57	1.50	1.42	1.36

Market Concentration

In 2022, the effective MW weighted average HHI of RegA resources was 2459 which is highly concentrated and the effective MW weighted average HHI of RegD resources was 1679 which is moderately concentrated. The effective MW weighted average HHI of all resources was 1416, which is moderately concentrated. The weighted average HHI reflects the fact that different owners have large market shares in the RegA and RegD markets.

Table 10-60 includes a monthly summary of three pivotal supplier (TPS) results. In 2022, the three pivotal supplier test was failed in 89.1 percent of hours. The MMU concludes that the PJM Regulation Market in 2022 was characterized by structural market power. The results presented here are calculated by PJM. The MMU has been unable to verify these results, as some of the underlying data necessary to replicate these calculations are not saved. PJM has submitted a request to the vendor to save all data necessary for verification.

Table 10-60 Regulation market monthly three pivotal supplier results: January 2020 through December 2022

Month	Percent of Hours Pivotal 2020	Percent of Hours Pivotal 2021	Percent of Hours Pivotal 2022
Jan	99.1%	91.4%	94.5%
Feb	97.4%	88.7%	84.1%
Mar	98.3%	87.2%	90.1%
Apr	96.5%	88.5%	92.8%
May	94.9%	83.9%	91.4%
Jun	89.8%	86.4%	85.7%
Jul	89.0%	86.4%	88.2%
Aug	94.6%	76.3%	86.4%
Sep	93.3%	82.9%	86.1%
Oct	94.0%	91.9%	86.7%
Nov	91.0%	86.7%	91.0%
Dec	83.6%	80.1%	92.2%
Average	93.5%	85.9%	89.1%

Market Conduct

Offers

Resources seeking to regulate must qualify to follow a regulation signal by passing a test for that signal with at least a 75 percent performance score. The regulating resource must be able to supply at least 0.1 MW of regulation and not allow the sum of its regulating ramp rate and energy ramp rate to exceed its overall ramp rate.[114] When offering into the regulation market, regulating resources must submit a cost-based offer and may submit a price-based offer (capped at $100 per MW) by 1415 the day before the operating day.[115]

Offers in the PJM Regulation Market consist of a capability component for the MW of regulation capability provided and a performance component for the miles (ΔMW of regulation movement) provided. The capability component for cost-based offers is not to exceed the increased fuel costs resulting from operating the regulating unit at a lower output level than its economically optimal output level, plus a $12.00 per MW margin. The $12.00 margin embeds market power in the regulation offers, is not part of the cost of regulation, and should be eliminated. The performance component for cost-based offers is not to exceed the increased costs (increased short run marginal costs including increased fuel costs) resulting from moving the unit up and down to provide regulation. Batteries and flywheels have zero cost for lower efficiency from providing regulation instead of energy, as they are not net energy producers. There is an energy storage loss component for batteries and flywheels as a cost component of regulation performance offers to reflect the net energy consumed to provide regulation service.[116]

Up until one hour before the operating hour, the regulating resource must provide: status (available, unavailable, or self scheduled); capability (movement up and down in MW); regulation maximum and regulation minimum (the highest and lowest levels of energy output while regulating in MW); and the regulation signal type (RegA or RegD). Resources may offer regulation for both the RegA and RegD signals, but will be assigned to follow only one signal for a given operating hour. Resources have the option to submit a minimum level of regulation they are willing to provide.[117]

All LSEs are required to provide regulation in proportion to their load share. LSEs can purchase regulation in the regulation market, purchase regulation from other providers bilaterally, or self schedule regulation to satisfy their obligation (Table 10-63).[118] Figure 10-24 compares average hourly regulation and self scheduled regulation during ramp and nonramp hours on an effective MW basis. Self scheduled regulation averaged 39.7 percent of all effective MW during ramp hours (46.0 percent in 2021) and 56.2 percent of all effective MW during nonramp hours (61.3 percent in 2021) in 2022. Over all hours in 2022, self scheduled regulation averaged 46.2 percent of all effective MW (52.1 percent in 2021) (See Table 10-61). The average hourly regulation is the amount of regulation that actually cleared and is not the same as the regulation requirement because PJM clears the market within a two percent band around the requirement.[119]

Figure 10-24 Nonramp and ramp regulation levels: January 2021 through December 2022

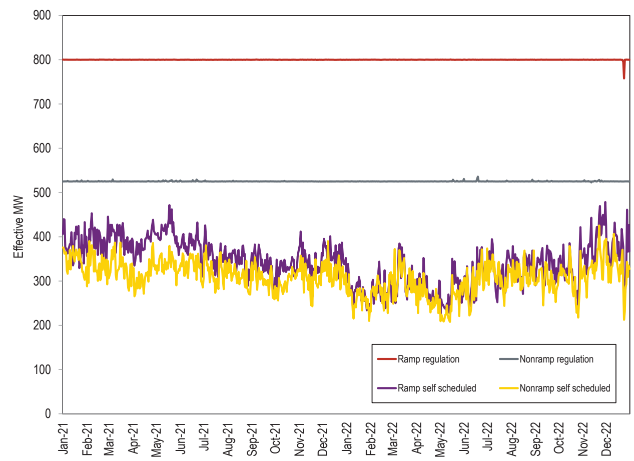


Table 10-61 Total Effective MW and Self Scheduled Effective MW during ramp and non ramp hours: 2021 and 2022

Year		Effective MW	Self Scheduled Effective MW	Percent Effective MW
2021	Ramp	291,987.0	134,378.2	46.0%
	Non Ramp	191,689.2	117,470.8	61.3%
Total		483,676.1	251,849.1	52.1%
2022	Ramp	291,954.0	115,764.8	39.7%
	Non Ramp	191,703.0	107,788.5	56.2%
Total		483,656.9	223,553.3	46.2%

Table 10-62 shows the role of RegD resources in the regulation market. RegD resources are both a growing proportion of the market (10.9 percent of the total effective MW at the start of the performance based regulation market design in October 2012 and 45.7 percent of the total effective MW in December 2022) and a growing proportion of resources that self schedule (25.0 percent of all self scheduled effective MW in

114 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 122 (Oct. 1, 2022).
115 Id. at 3.2.2, at p 62.
116 See "PJM Manual 15: Cost Development Guidelines," § 7.8 Regulation Cost, Rev. 42 (Oct. 28, 2022).
117 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 122 (Oct. 1, 2022).
118 See "PJM Manual 28: Operating Agreement Accounting," § 4.1 Regulation Accounting Overview, Rev. 89 (Nov.. 1, 2022).
119 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 122 (Oct. 1, 2022).

October 2012 and 64.4 percent of all self scheduled effective MW in December 2022). In 2022, the average RegD percentage of total self scheduled effective MW was 66.6 percent, a decrease of 5.1 percentage points from 2021, when the average was 71.7 percent.

Table 10-62 RegD self scheduled regulation by month: January 2021 through December 2022

Year	Month	RegD Self Scheduled Effective MW	RegD Effective MW	Total Self Scheduled Effective MW	Total Effective MW	RegD Percent of Total Self Scheduled Effective MW	RegD Percent of Total Effective MW
2021	Jan	250.5	322.4	367.7	674.0	68.1%	47.8%
2021	Feb	262.0	335.3	366.7	674.3	71.4%	49.7%
2021	Mar	263.0	321.7	359.0	639.9	73.3%	50.3%
2021	Apr	266.0	325.9	343.1	639.6	77.5%	51.0%
2021	May	256.8	320.6	368.0	639.9	69.8%	50.1%
2021	Jun	266.5	329.9	362.7	697.0	73.5%	47.3%
2021	Jul	255.4	331.6	344.6	696.9	74.1%	47.6%
2021	Aug	242.6	326.1	330.2	698.9	73.5%	46.7%
2021	Sep	219.8	302.0	319.6	639.6	68.8%	47.2%
2021	Oct	223.6	301.0	311.1	639.8	71.9%	47.1%
2021	Nov	218.5	298.9	321.2	640.3	68.0%	46.7%
2021	Dec	239.3	316.3	341.4	673.9	70.1%	46.9%
2021 Average		247.0	332.0	344.6	662.8	71.7%	48.2%
2022	Jan	211.8	295.7	267.8	674.0	79.1%	43.9%
2022	Feb	193.7	285.2	278.7	674.0	69.5%	42.3%
2022	Mar	202.1	285.3	305.6	639.8	66.1%	44.6%
2022	Apr	191.5	274.9	270.0	639.6	70.9%	43.0%
2022	May	191.2	276.4	258.3	639.8	74.0%	43.2%
2022	Jun	201.5	296.7	302.4	697.2	66.6%	42.6%
2022	Jul	192.7	299.8	321.1	696.9	60.0%	43.0%
2022	Aug	205.6	308.3	328.0	697.0	62.7%	44.2%
2022	Sep	196.4	300.0	314.3	639.3	62.5%	46.9%
2022	Oct	207.5	307.4	312.0	640.0	66.5%	48.0%
2022	Nov	203.2	300.5	360.2	640.7	56.4%	46.9%
2022	Dec	225.1	307.7	349.4	673.2	64.4%	45.7%
2022 Average		201.9	294.8	305.6	662.6	66.6%	44.5%

LSE's can satisfy their obligation to provide regulation by purchasing in the spot market, self scheduling, or through bilateral agreements. Increased self scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. For total spot market regulation and self scheduled regulation, Table 10-63 shows monthly data for 2021 and 2022, and Table 10-64 shows annual data for 2012 through 2022. Table 10-63 and Table 10-64 are based on settled (purchased) MW.

Table 10-63 Regulation sources: spot market and self scheduled purchases: January 2021 through December 2022

Year	Month	Spot Market Regulation (Unadjusted MW)	Self Scheduled Regulation (Unadjusted MW)
2021	Jan	186,762.8	192,708.2
2021	Feb	172,967.1	174,470.7
2021	Mar	182,812.8	189,176.1
2021	Apr	190,444.5	170,255.4
2021	May	171,841.5	198,026.9
2021	Jun	211,800.7	163,167.4
2021	Jul	225,587.1	162,774.7
2021	Aug	234,148.0	154,435.7
2021	Sep	190,656.5	150,785.2
2021	Oct	212,564.6	150,788.9
2021	Nov	191,647.2	151,450.1
2021	Dec	211,012.8	164,679.9
Total		2,382,245.5	2,022,719.3
2022	Jan	257,948.1	110,706.4
2022	Feb	220,778.9	113,317.3
2022	Mar	208,538.9	145,113.8
2022	Apr	215,631.5	116,433.1
2022	May	219,531.8	111,742.8
2022	Jun	217,223.5	134,779.2
2022	Jul	188,416.3	158,033.3
2022	Aug	193,928.6	158,307.5
2022	Sep	148,455.0	153,563.6
2022	Oct	196,730.2	152,760.3
2022	Nov	138,069.0	174,439.7
2022	Dec	183,940.9	172,713.5
Total		2,389,192.7	1,701,910.6

Table 10-64 Regulation sources: spot market and self scheduled: 2012 through 2022

Year	Spot Market Regulation (Unadjusted MW)	Self Scheduled Regulation (Unadjusted MW)
2012	6,149,110.0	1,484,446.2
2013	3,088,963.1	2,064,156.7
2014	2,327,322.4	2,161,996.5
2015	2,546,688.3	1,888,040.0
2016	2,260,701.6	2,104,775.1
2017	2,504,264.1	1,783,045.7
2018	2,755,355.7	1,558,388.9
2019	2,367,346.1	1,867,285.3
2020	2,156,968.5	2,215,555.1
2021	2,382,245.5	2,022,719.3
2022	2,426,586.3	1,705,256.9

In 2022, DR provided an average of 21.1 MW of regulation per hour during ramp hours (10.9 MW of regulation per hour during ramp hours in 2021), and an average of 16.2 MW of regulation per hour during nonramp hours (7.5 MW of regulation per hour during nonramp hours in 2021). Generating units supplied an average of 1,080.5 MW of regulation per hour during ramp hours in 2022 (1,055.4 MW of regulation per hour during ramp hours in 2021), and an average of 730.4 MW per hour during nonramp hours in 2022 (733.3 MW of regulation per hour during nonramp hours in 2021).

Market Performance

Price

Table 10-65 shows the regulation price and regulation cost per MW for 2009 through 2022. The weighted average RMCP for 2022 was $53.53 per MW. This is an increase of $27.52 per MW, or 105.8 percent, from the weighted average RMCP of $26.00 per MW in 2021. This increase in the regulation clearing price was the result of an increase in energy prices in 2022 and the related increase in the opportunity cost component of RMCP.

Table 10-65 Comparison of average price and cost for regulation: 2009 through 2022

Year	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent of Cost
2009	$23.00	$30.68	75.0%
2010	$18.00	$32.86	54.8%
2011	$16.49	$29.72	55.5%
2012	$19.02	$25.32	75.1%
2013	$30.85	$35.79	86.2%
2014	$44.49	$53.82	82.7%
2015	$31.92	$38.36	83.2%
2016	$15.73	$18.13	86.7%
2017	$16.79	$23.03	72.9%
2018	$25.32	$31.94	79.3%
2019	$16.27	$20.32	80.1%
2020	$13.55	$16.73	81.0%
2021	$26.00	$31.49	82.6%
2022	$53.53	$65.10	82.2%

The introduction of fast start pricing in the PJM energy market on September 1, 2021, had an effect on the regulation market LOC included in regulation offers and in the resulting clearing price for regulation. Table 10-66 shows the effect of fast start pricing on the regulation market monthly capability component of price and the total regulation market clearing price from September 2021 through December, 2022. In 2022, fast start pricing increased the average regulation market clearing price by 6.3 percent compared to dispatch pricing.

Table 10-66 Comparison of fast start and dispatch pricing: September 2021 through December 2022[120]

		Weighted Average Price ($/Perf. Adj. Actual MW)				
		Capability Clearing Price		Regulation Market Clearing Price		
Year	Month	Dispatch	Fast Start	Dispatch	Fast Start	Percent Fast Start Increase
2021	Sep	$27.22	$29.08	$28.55	$30.41	6.5%
	Oct	$35.64	$39.92	$37.12	$41.40	11.5%
	Nov	$50.56	$54.40	$52.43	$56.28	7.3%
	Dec	$25.62	$27.37	$27.05	$28.79	6.4%
2022	Jan	$68.25	$71.14	$69.68	$72.56	4.1%
	Feb	$31.14	$31.93	$32.76	$33.55	2.4%
	Mar	$23.91	$25.94	$25.70	$27.73	7.9%
	Apr	$45.07	$48.85	$47.49	$51.27	7.9%
	May	$38.09	$41.85	$39.84	$43.60	9.4%
	Jun	$47.26	$52.57	$49.17	$54.48	10.8%
	Jul	$47.40	$54.51	$48.92	$56.04	14.5%
	Aug	$57.43	$64.13	$59.17	$65.87	11.3%
	Sep	$46.17	$48.84	$48.07	$50.73	5.5%
	Oct	$33.38	$36.76	$35.33	$38.70	9.6%
	Nov	$21.29	$23.08	$22.42	$24.21	8.0%
	Dec	$115.65	$112.73	$116.94	$114.03	(2.5%)
Yearly		$48.66	$51.82	$50.37	$53.53	6.3%

Figure 10-25 shows the capability price, performance price, and the opportunity cost component for the PJM Regulation Market on a performance adjusted MW basis. The regulation clearing price is determined based on the marginal unit's total offer (RCP + RPP + PJM calculated LOC). Then the maximum performance offer price (RPP) of any of the cleared units is used to set the marginal performance clearing price for the purposes of settlements. The difference between the marginal total clearing price and the highest performance clearing price (RMPCP) is the marginal capability clearing price (RMCCP). The capability price presented here is equal to the clearing price, minus the maximum cleared performance offer price. This data is based on actual five minute interval operational data.

Figure 10-25 illustrates the components of the regulation market clearing price. Each section represents the contribution of the lost opportunity cost (green area), capability price (blue area), and performance price (orange area), to the total price. From this figure, it is clear that the lost opportunity cost is the predominant component of the total clearing price.

Figure 10-25 Regulation market clearing price components (Dollars per MW): 2022

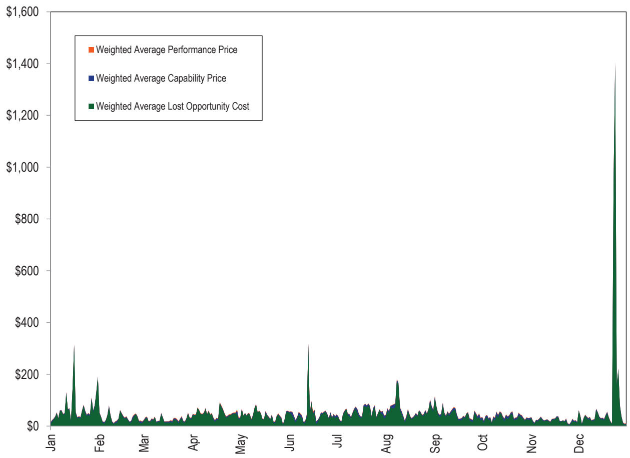


Table 10-67 shows the capability and performance components of the monthly average regulation prices. These components differ from the components of the marginal unit's offers in Figure 10-25 because the performance component of the settlement price for each hour is determined from the average of the highest performance offers in each five minute interval, calculated independent of the marginal unit's offers in those intervals.

120 The performance component of the regulation market clearing price is unaffected by fast start pricing.

Table 10-67 Regulation market monthly component of price (Dollars per MW): January through December, 2022

Month	Weighted Average Regulation Market Capability Clearing Price ($/Perf. Adj. Actual MW)	Weighted Average Regulation Market Performance Clearing Price ($/Perf. Adj. Actual MW)	Weighted Average Regulation Market Clearing Price ($/Perf. Adj. Actual MW)
Jan	$71.14	$1.43	$72.56
Feb	$31.93	$1.62	$33.55
Mar	$25.94	$1.79	$27.73
Apr	$48.85	$2.42	$51.27
May	$41.85	$1.75	$43.60
Jun	$52.57	$1.92	$54.48
Jul	$54.51	$1.52	$56.04
Aug	$64.13	$1.74	$65.87
Sep	$48.84	$1.89	$50.73
Oct	$36.76	$1.95	$38.70
Nov	$23.08	$1.13	$24.21
Dec	$112.73	$1.29	$114.03
Average	$51.82	$1.71	$53.53

Monthly and total annual scheduled regulation MW and regulation charges, as well as monthly average regulation price and regulation cost are shown in Table 10-68. Total scheduled regulation is based on settled performance adjusted MW. The total of all regulation charges in 2022 was $296,241,818 million, compared to $144,375,702 million in 2021.

Table 10-68 Total regulation charges: January 2021 through December 2022

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percent of Cost
2021	Jan	400,937.0	$6,038,564	$12.12	$15.06	80.5%
2021	Feb	364,533.3	$9,401,619	$20.60	$25.79	79.9%
2021	Mar	386,898.9	$8,793,373	$19.20	$22.73	84.5%
2021	Apr	373,462.9	$7,951,303	$17.34	$21.29	81.5%
2021	May	386,138.5	$8,051,297	$16.62	$20.85	79.7%
2021	Jun	390,494.1	$9,654,112	$19.22	$24.72	77.8%
2021	Jul	403,379.4	$9,696,300	$20.02	$24.04	83.3%
2021	Aug	404,161.2	$15,414,276	$33.13	$38.14	86.9%
2021	Sep	355,337.7	$12,923,840	$30.41	$36.37	83.6%
2021	Oct	373,226.9	$18,334,407	$41.40	$49.12	84.3%
2021	Nov	356,980.3	$24,453,797	$56.28	$68.50	82.2%
2021	Dec	389,951.2	$13,662,814	$28.79	$35.04	82.2%
Yearly		4,585,501.3	$144,375,702	$26.00	$31.49	82.6%
2022	Jan	384,969.5	$34,046,042	$72.56	$88.44	82.1%
2022	Feb	349,755.8	$14,317,381	$33.53	$40.94	81.9%
2022	Mar	367,002.2	$13,057,959	$27.73	$35.58	77.9%
2022	Apr	355,900.6	$23,257,413	$51.27	$65.35	78.5%
2022	May	360,870.6	$19,641,413	$43.60	$54.43	80.1%
2022	Jun	384,946.7	$25,593,008	$54.48	$66.48	82.0%
2022	Jul	396,606.5	$28,295,746	$56.04	$71.34	78.5%
2022	Aug	391,060.2	$32,350,728	$65.87	$82.73	79.6%
2022	Sep	346,887.7	$21,260,643	$50.73	$61.29	82.8%
2022	Oct	377,096.5	$19,140,156	$38.70	$50.76	76.3%
2022	Nov	352,936.7	$11,434,507	$24.21	$32.40	74.7%
2022	Dec	396,257.4	$53,839,022	$114.03	$135.87	83.9%
Yearly		4,550,354.2	$296,241,818	$53.53	$65.10	82.2%

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-69. Total scheduled regulation is based on settled performance adjusted MW. In 2022, the average total cost of regulation was $65.10 per MW, 106.8 percent higher than $31.49 in 2021. In 2022, the monthly average capability component cost of regulation was $51.78, 105.1 percent higher than $25.25 in 2021. In 2022, the monthly average performance component cost of regulation was $4.00, 36.1 percent higher than $2.94 in 2021. The increase of the average total cost in 2022 versus 2021, was primarily a result of higher LOC values due to higher prices in the energy market.

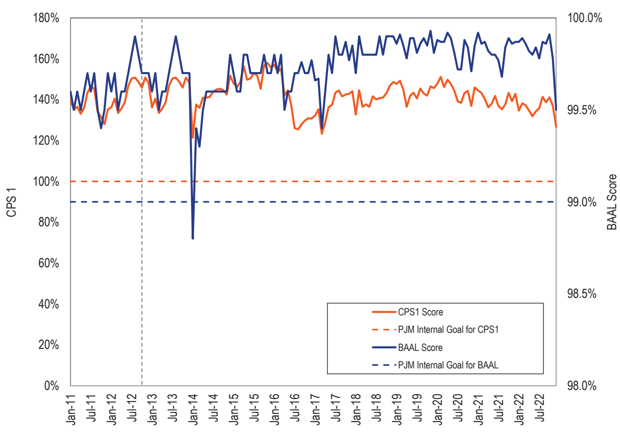
Table 10-69 Components of regulation cost: January 2021 through December 2022

Year	Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
2021	Jan	400,937.0	$11.71	$1.67	$1.68	$15.06
	Feb	364,533.3	$19.90	$2.52	$3.37	$25.79
	Mar	386,898.9	$18.70	$1.86	$2.16	$22.73
	Apr	373,462.9	$16.63	$2.66	$2.00	$21.29
	May	386,138.5	$15.87	$2.40	$2.58	$20.85
	Jun	390,494.1	$18.45	$2.54	$3.73	$24.72
	Jul	403,379.4	$19.25	$2.68	$2.10	$24.04
	Aug	404,161.2	$32.19	$3.36	$2.58	$38.14
	Sep	355,337.7	$29.45	$3.41	$3.52	$36.37
	Oct	373,226.9	$40.60	$3.97	$4.55	$49.12
	Nov	356,980.3	$55.46	$4.80	$8.24	$68.50
	Dec	389,951.2	$27.87	$3.67	$3.50	$35.04
Yearly		4,585,501.3	$25.25	$2.94	$3.29	$31.49
2022	Jan	384,969.5	$72.12	$3.22	$13.10	$88.44
	Feb	349,755.8	$32.50	$3.77	$4.66	$40.94
	Mar	367,002.2	$26.45	$4.35	$4.78	$35.58
	Apr	355,900.6	$49.80	$5.67	$9.88	$65.35
	May	360,870.6	$43.22	$4.19	$7.02	$54.43
	Jun	384,946.7	$53.72	$4.38	$8.38	$66.48
	Jul	396,606.5	$56.22	$3.59	$11.53	$71.34
	Aug	391,060.2	$66.80	$4.32	$11.61	$82.73
	Sep	346,887.7	$51.27	$4.87	$5.16	$61.29
	Oct	377,096.5	$36.74	$4.84	$9.18	$50.76
	Nov	352,936.7	$23.08	$2.86	$6.46	$32.40
	Dec	396,257.4	$112.51	$3.06	$20.29	$135.87
Yearly		4,550,354.2	$51.78	$4.00	$9.32	$65.10

Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-26 for every month from January 2011 through December 2022 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[121] The horizontal dashed lines represent PJM internal goals for CPS1 and BAAL performance.

Figure 10-26 Monthly CPS1 and BAAL performance: January 2011 through December 2022



121 See *2019 State of the Market Report for PJM*, Appendix F: Ancillary Services.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[122] Although the issue is being addressed in the stakeholder process, there are currently no firm fuel requirements for black start units.

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of cost of service rates defined in the tariff.[123] Currently, there is a small number of units in unique circumstances with bilateral agreements with their transmission operator (TO) to provide black start service that were entered into prior to joining PJM. These units are compensated directly by the TO.

PJM defines required black start capability zonally, while recognizing that the most effective way to provide black start service may be across zones. Under the current rules PJM has substantial flexibility in procuring black start resources and is responsible for black start resource selection.

On April 7, 2021, PJM issued an incremental RFP for additional black start service in the BGE and PEPCO Zones. On November 1, 2021, PJM made awards for the April 7, 2021 incremental RFP. The planned in service date is April 1, 2023. On August 1, 2022, PJM issued an incremental RFP for additional black start service in the PECO Zone. PJM plans to make a decision by the end of February 2023.[124]

Total black start charges are the sum of black start revenue requirement charges and black start uplift (operating reserve) charges.

Black start revenue requirements for black start units consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor applicable when CRF rates are not used. The tariff specifies how to calculate each component of the revenue requirement formula.[125]

Fixed black start service costs are calculated using one of three methods chosen by the black start provider from the options defined in the OATT Schedule 6A: base formula rate; capital cost recovery rate; or incremental black start NERC-CIP cost recovery. The base formula rate is calculated by taking the net CONE multiplied by the black start unit's capacity multiplied by an x factor. The x factor is 0.01 for hydro units and 0.02 for CT units. The capital recovery rate is calculated by multiplying the capital investment by the CRF rate. The incremental NERC-CIP cost, for existing black start resources that need to add additional capital to meet NERC-CIP requirements, is calculated using the capital cost recovery rate. Black start uplift charges are paid to units committed in real time to provide black start service or for black start testing.[126] Total black start charges are allocated monthly to PJM customers based on their zone and nonzone peak transmission use and point to point transmission reservations.[127] It is not clear why it is reasonable to have different charges for black start service across zones as the service is to ensure that PJM as a whole can recover from a large scale outage.

In 2022, total black start charges were $68.6 million, an increase of $0.575 million (0.8 percent) from 2021. In 2022, total revenue requirement charges were $68.11 million, an increase of $0.415 million (0.6 percent) from 2021. In 2022, total uplift charges were $0.476 million, an increase of $.159 million (50.3 percent) from 2021. Table 10-70 shows total charges for each year from 2010 through 2022.[128]

122 OATT Schedule 1 § 1.3BB.
123 *See* OATT Schedule 6A para. 18.
124 RFPs issued can be found on the PJM website. See PJM. <http://www.pjm.com/markets-and-operations/ancillary-services.aspx>.
125 *See* OATT Schedule 6A para. 18.
126 There are no black start units currently using the ALR option.
127 OATT Schedule 6A (paras. 25, 26 and 27 outline how charges are to be applied).
128 Starting December 1, 2012, PJM defined a separate black start uplift category. ALR units accounted for the high uplift charges in 2013 – 2015. All ALR units had been replaced by April 2015.

Table 10-70 Black start revenue requirement charges: 2010 through 2022

Year	Revenue Requirement Charges	Uplift Charges	Total
2010	$11,490,379	$0	$11,490,379
2011	$13,695,331	$0	$13,695,331
2012	$18,749,617	$8,384,651	$27,134,269
2013	$20,874,535	$86,701,561	$107,576,097
2014	$26,945,112	$32,906,733	$59,851,845
2015	$56,425,648	$5,175,644	$61,601,292
2016	$69,376,257	$279,017	$69,655,275
2017	$69,258,169	$257,174	$69,515,342
2018	$64,439,926	$294,753	$64,734,679
2019	$64,327,918	$226,014	$64,553,932
2020	$64,643,080	$230,754	$64,873,834
2021	$67,694,868	$316,437	$68,011,305
2022	$68,110,179	$475,712	$68,585,891

Black start zonal charges in 2022 ranged from $0 in the OVEC and REC Zones to $19,478,693 in the AEP Zone. For each zone, Table 10-71 shows black start charges, zonal peak loads, and black start rates (calculated as charges per MW-day).[129] [130] Customers paid an average of $1.13 per MW-day for black start service in 2022.

Table 10-71 Black start zonal charges: 2021 and 2022[131]

	2021					2022				
Zone	Revenue Requirement Charges	Uplift Charges	Total Charges	Peak Load (MW)	Black Start Rate ($/MW-day)	Revenue Requirement Charges	Uplift Charges	Total Charges	Peak Load (MW)	Black Start Rate ($/MW-day)
ACEC	$2,256,528	$26,011	$2,282,539	3,522	$2.37	$1,965,301	$7,287	$1,972,587	2,631	$2.05
AEP	$19,741,659	$61,990	$19,803,649	28,899	$2.51	$19,478,693	$117,417	$19,596,110	21,925	$2.45
APS	$5,346,227	$1,135	$5,347,361	11,548	$1.70	$6,485,339	$8,630	$6,493,969	8,865	$2.01
ATSI	$5,581,214	$6,593	$5,587,807	16,666	$1.23	$5,549,962	$0	$5,549,962	12,604	$1.21
BGE	$43,535	$95	$43,630	8,958	$0.02	$37,482	$210	$37,692	6,486	$0.02
COMED	$9,353,385	$36,616	$9,390,000	27,034	$1.27	$9,061,097	$70,431	$9,131,529	21,167	$1.18
DAY	$233,178	$13,958	$247,136	4,424	$0.20	$208,907	$24,487	$233,394	3,330	$0.19
DUKE	$384,287	$12,598	$396,885	6,652	$0.22	$336,642	$14,831	$351,473	5,306	$0.18
DUQ	$294,366	$1,338	$295,705	3,566	$0.30	$1,016,749	$9,153	$1,025,903	2,759	$1.02
DOM	$5,226,310	$56,494	$5,282,803	26,821	$0.72	$5,016,477	$95,980	$5,112,457	20,405	$0.69
DPL	$1,621,172	$15,479	$1,636,651	5,462	$1.10	$1,181,487	$20,906	$1,202,393	4,006	$0.82
EKPC	$332,380	$2,076	$334,456	3,636	$0.34	$268,686	$8,053	$276,739	2,851	$0.27
JCPLC	$677,277	$2,564	$679,841	7,893	$0.32	$549,651	$6,005	$555,656	6,169	$0.25
MEC	$500,219	$20,033	$520,253	3,979	$0.48	$470,624	$31,060	$501,683	3,072	$0.45
OVEC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
PECO	$1,459,560	$2,199	$1,461,759	10,894	$0.49	$1,344,940	$4,489	$1,349,429	8,479	$0.44
PE	$4,368,997	$12,851	$4,381,848	3,892	$4.12	$4,315,505	$11,347	$4,326,852	2,900	$4.09
PEPCO	$331,736	$10,971	$342,707	7,870	$0.16	$277,972	$8,146	$286,119	5,829	$0.13
PPL	$4,876,895	$10,154	$4,887,050	9,707	$1.84	$4,878,663	$3,013	$4,881,676	7,517	$1.78
PSEG	$1,749,798	$9,300	$1,759,098	12,778	$0.50	$1,677,033	$8,379	$1,685,412	10,064	$0.46
REC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
(Imp/Exp/Wheels)	$3,316,144	$13,983	$3,330,127	10,517	$1.16	$3,988,970	$25,888	$4,014,858	9,738	$1.13
Total	$67,694,868	$316,437	$68,011,305	214,720	$1.16	$68,110,179	$475,712	$68,585,891	166,102	$1.13

Table 10-72 provides a revenue requirement estimate by zone for the 2022/2023, 2023/2024, and 2024/2025 Delivery Years.[132] Revenue requirement values are rounded up to the nearest $50,000, reflecting the uncertainty about future black start revenue requirement costs. These values are illustrative only. The estimates are based on the best available data including current black start unit revenue requirements, expected black start unit termination and in service dates, changes in recovery rates, and owner provided cost estimates of incoming black start units at the time of publication and may change significantly. The estimates do not reflect the impact of FERC decisions that could affect compensation for black start.

129 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 7.3 Black Start Service Charges, Rev. 96 (Dec. 21, 2022).
130 For each zone and import export/wheels the black start rates ($/MW day) are calculated by taking total charges by zone and divided by peak load then divided by days in the period.
131 Peak load for each zone is used to calculate the black start rate per MW day.
132 The System Restoration Strategy Task Force requested that the MMU provide estimated black start revenue requirements.

Table 10-72 Black start zonal revenue requirement estimate: 2022/2023 through 2024/2025 Delivery Years[133]

Zone	2022 / 2023 Revenue Requirement	2023 / 2024 Revenue Requirement	2024 / 2025 Revenue Requirement
ACEC	$2,100,000	$2,100,000	$2,100,000
AEP	$20,600,000	$20,700,000	$15,800,000
APS	$6,950,000	$6,950,000	$6,950,000
ATSI	$5,950,000	$5,950,000	$3,950,000
BGE	$50,000	$350,000	$3,500,000
COMED	$9,400,000	$9,650,000	$9,650,000
DAY	$250,000	$250,000	$250,000
DUKE	$350,000	$400,000	$400,000
DUQ	$1,100,000	$1,100,000	$1,100,000
DOM	$5,250,000	$5,350,000	$5,350,000
DPL	$1,250,000	$1,350,000	$1,350,000
EKPC	$300,000	$350,000	$350,000
JCPLC	$550,000	$650,000	$650,000
MEC	$500,000	$550,000	$550,000
OVEC	$0	$0	$0
PECO	$1,400,000	$1,550,000	$1,550,000
PE	$4,550,000	$4,650,000	$4,650,000
PEPCO	$250,000	$650,000	$5,550,000
PPL	$5,250,000	$5,300,000	$5,300,000
PSEG	$1,750,000	$1,800,000	$1,800,000
REC	$0	$0	$0
Total	$67,800,000	$69,650,000	$70,800,000

CRF Issues

The capital recovery factor (CRF) defines the revenue requirement of black start units when new equipment is added to provide black start capability.[134] The CRF is a rate, which when multiplied by the investment, provides for a return on and of capital over a defined time period. CRFs are calculated using a formula (or a correctly defined standard financial model) that accounts for the weighted average cost of capital and its components, plus depreciation and taxes. The PJM CRF table was created in 2007 as part of the new RPM capacity market design and incorporated in Attachment DD to the PJM OATT. That CRF table provided for the accelerated return of incremental investment in capacity resources based on concerns about the fact that some old coal units would be making substantial investments related to pollution control. The CRF values were later added to the black start rules.[135] The CRF table in the tariff included assumptions about tax rates that were significantly too high after the changes to the tax code in 2017. The PJM tariff tables including CRF values should have been changed for both black start and the capacity market when the tax laws changed in 2017.

133 The 2024/2025 estimated revenue requirement is based on the CONE values for the 2023/2024 RPM Base Residual Auction because the 2024/2025 RPM Base Residual Auction has not been run.

134 *See* OATT Schedule 6A para. 18.

135 *Id.*

The CRF table for existing black start units includes the column header, term of black start commitment, which is misleading and incorrect. The column is simply the cost recovery period. Accelerated recovery reduces risk to black start units and should not be the basis for a shorter commitment. Full payment of all costs of black start investment on an accelerated basis should not be a reason for a shortened commitment period. Regardless of the recovery period, payment of the full costs of the black start investment should require commitment for the life of the unit.[136] In addition, there is no need for such short recovery periods for black start investment costs. Two periods, based on unit age, are more than adequate.

The U.S. Internal Revenue Code changed significantly in December 2017.[137] The PJM CRF table did not change to reflect these changes.[138] [139] As a result, CRF values have overcompensated black start units since the changes to the tax code. The new tax law allow for a more accelerated depreciation and reduced the corporate tax rate to 21 percent.

Updated CRF rates, incorporating the tax code changes and applicable to all black start units, should be implemented immediately. The updated CRF rates should apply to all black start units because the actual tax payments for all black start units were reduced by the tax law changes. Without this change, black start units are receiving and will continue to receive an unexpected and inappropriate windfall.

On April 7, 2021, PJM filed with FERC to update the CRF values for new black start service units.[140] PJM proposed to bifurcate the CRF calculation, applying an updated CRF calculation that incorporates the new federal tax law to new black start units while leaving the outdated and incorrect CRF in place for existing black start units. Rather than fix the inaccurate CRF values used for existing black units, PJM's filing would have made the use of inaccurate values permanent. The MMU filed

136 PJM's recent filing to revise Schedule 6A includes a required commitment to provide black start service for the life of the unit. See FERC Docket No. ER21-1635.

137 Tax Cuts and Jobs Act, Pub. L. No. 115-97, 131 Stat. 2096, Stat. 2105 (2017)

138 The corporate tax rate was lowered to 21 percent and bonus depreciation, which allows generator owners to depreciate 100 percent of the capital investment in the first year of operation, was introduced.

139 Bonus depreciation is 100 percent for capital investments placed in service after September 27, 2017 and before January 1, 2023. Bonus depreciation is 80 percent for capital investments placed in service after December 31, 2022 and before January 1, 2024, and the bonus depreciation level is reduced by 20 percent for each subsequent year through 2026. Capital investments placed in service after December 31, 2026 are not eligible for bonus depreciation. See 26 U.S. Code §168(k)(6)(A).

140 *See* Docket No. ER21-1635-000.

comments on April 28, 2021.[141] The MMU objected to the continued use of the outdated CRF for existing units. The MMU also introduced a CRF formula for calculating the CRF for new black start units and requested that the CRF formula be included in the tariff.[142] [143] On August 10, 2021, FERC issued an order ("August 10th Order") that accepted PJM's tariff revisions that apply to new black start units (selected for service after June 6, 2021) and directed PJM to include the CRF formula proposed by the MMU.[144] The August 10th Order also established a show cause proceeding in a new docket to "determine whether the existing rates for generating units providing Black Start Service (Black Start Units), which are based on a federal corporate income tax that pre-dates the Tax Cuts and Jobs Act of 2017 (TCJA), remains just and reasonable."[145] The MMU requested rehearing over the Commission's conclusion that the MMU had requested "retroactive changes to the rates previously paid to generators."[146] [147] The request for rehearing was denied.[148] PJM's compliance filing to address the August 10 Order was accepted by letter order, subject to edits proposed by the MMU, on December 16, 2021.[149]

PJM's response to the show cause directive in the August 10th Order continued to support the use of the outdated CRF despite the Commission's statement that the CRF values "appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful."[150] [151] The MMU responded with analysis showing that PJM's proposal for maintaining the outdated CRF values would result in $126 million of over recovery of black start capital investments.[152] Table 10-73 shows the over recovery of capital payments by resources awarded black start service prior to Jun 6, 2021 as result of PJM's continued application of the old CRF rate.

Table 10-73 CRF over recovery if CRF not corrected for changes in tax laws[153]

	Excess Payback ($ millions)	Percent
Began black start service prior to the effective date of the TCJA	$36.0	28.4%
Began black start service on or after the effective date of the TCJA	$90.7	71.6%
Total	$126.8	

The MMU also proposed an update to the CRF that reflects the return of capital already received by existing black start units and eliminates the over recovery that occurs under the PJM proposal. The updated CRF would be set at the level that covers the tax liabilities going forward, pays a return at the required rates on the remaining capital investment, pays back the full investment and results in the required return on and of capital over the CRF term. A description of the MMU's proposal and a formula for calculating the updated CRF are included in the MMU Comments.[154]

NERC – CIP

No black start units have requested new or additional black start NERC – CIP Capital Costs.[155]

Reactive Service and Capability

Suppliers of reactive power are compensated separately for reactive service and reactive capability.

Reactive service, reactive supply and voltage control are provided by generation and other sources of reactive power, including static VAR compensators and capacitor banks. Reactive power helps maintain appropriate voltage levels on the transmission system and is essential to the flow of real power (measured in MW). The same equipment provides both MVAr and MW. Generation resources are required to meet defined reactive capability requirements as a condition to receive interconnection service in PJM.[156] In a 2023 MISO case, the Commission affirmed that RTOs and their customers are not required to compensate generation resources for such reactive capability.[157] Customers in PJM, nevertheless, pay $384.0

141 See Comments of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635-000 (April 28, 2021), which can be accessed at <http://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_No_ER21-1635_20210428.pdf>.
142 Answer and Motion for Leave to Answer of the independent Market Monitor for PJM, ER21-1635 (May 20, 2021).
143 Comments of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635 (July 2, 2021).
144 176 FERC ¶ 61,080 at 42 and 44 (2021).
145 176 FERC ¶ 61,080 at 2 (2021).
146 Id. at 50.
147 Request for Rehearing of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635 (September 9, 2021).
148 177 FERC ¶ 62,017 (2021).
149 177 FERC ¶ 61,202 (2021).
150 *PJM Interconnection, L.L.C., Response to Commission's Show Cause Order*, Docket No. EL21-91 (October 12, 2021).
151 August 10th Oder at 47.
152 Errata Filing of the Independent Market Monitor for PJM, Attachment B at 17, Docket No. EL21-91 (November 18, 2022).
153 Black start generators in service prior to September 27, 2017, the effective date of the Tax Cuts and Jobs Act (TCJA), are not eligible for bonus depreciation but do benefit from the lower corporate tax rate. Generators placed in black start service on or after September 27, 2017 benefit from the lower tax rate and bonus depreciation.
154 Id. (Attachment B, Section H at 18).
155 OATT Schedule 6A para. 21. "The Market Monitoring Unit shall include a Black Start Service summary in its annual State of the Market report which will set forth a descriptive summary of the new or additional Black Start NERC-CIP Capital costs requested by Black Start Units, and include a list of the types of capital costs requested and the overall cost of such capital improvements on an aggregate basis such that no data is attributable to an individual Black Start Unit."
156 OATT Attachment O.
157 *See MISO*, 182 FERC ¶ 61,033 at P 52 (January 27, 2023) (*MISO*); *see also Standardization of Generator Interconnection Agreements & Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at P 546 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 at P 28, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401

million in nonmarket costs for reactive capability based on a nonmarket view of cost allocation.

Compensation for reactive capability is approved separately for each resource or resource group by FERC per Schedule 2 of the OATT.[158] Reactive capability charges are based on FERC approved filings for individual unit revenue requirements that are typically black box settlements.[159] Reactive service charges are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive service. Compensation for reactive power service is based on real-time lost opportunity costs.[160]

Total reactive capability charges are the sum of FERC approved reactive supply revenue requirements. Zonal reactive supply revenue requirement charges are allocated monthly to PJM customers based on their zonal and to any nonzonal (outside of PJM) peak transmission use and daily average point to point transmission reservations.[161] [162]

In 2016, FERC began to reexamine its policies on reactive compensation.[163] On November 18, 2021, the FERC issued a notice of inquiry (NOI) concerning reactive power capability compensation.[164] The Market Monitor responded to the NOI.[165] The Commission's finding in the 2023 *MISO* case affirms that RTOs and their customers are not required to compensate generation resources for reactive capability.[166] Although this policy had been the practice in CAISO and SPP, *MISO* shows that an RTO can remove compensation for reactive capability from its market rules.[167]

Issues with Reactive Capability Market Design

The NOI inquires about reactive power capability compensation under the *AEP* Method, alternative methods of compensation, and resources interconnected at the distribution level. The fundamental question is whether market design in the organized wholesale markets requires separate, guaranteed cost of service compensation for reactive capability. The answer is no. All generation resources are required meet certain reactive capability requirements as a condition to receive interconnection service and no separate compensation is required.[168] In the PJM market design, investment in resources is fully recoverable through markets. The PJM markets are a complete set of markets that are self sustaining. Unlike some ISO/RTO designs, the PJM market design relies on markets rather than cost of service regulation or bilateral contracts to pay for capacity. Generators will invest in markets when the expected revenues provide for the payment of all costs and a return on and of capital. That is the way competitive markets work. It would be more equitable, more consistent with the PJM competitive market design, and more consistent with appropriate compensation for all generator costs, including reactive, to rely on PJM markets than to continue the outdated mixing of regulatory paradigms.

Even if the PJM design worked in the way asserted by supporters of cost of service payments for reactive, the best possible outcome would be the same as the market outcome. There would be an opportunity to recover all costs. A simple application of Occam's razor implies that the market approach should be used, as it is overwhelmingly more efficient than the current rate case, cost of service approach. Supporters of the cost of service approach have never explained why customers should be required to pay costs that generation resources are not entitled to recover from customers, why a nonmarket approach is required in PJM or why it is preferable to a market approach.

The current process is an inefficient waste of time because it relies on an atavistic regulatory paradigm that is not relevant in the PJM market framework. The

(2005), *aff'd sub nom. National Association of Regulatory Utility Commissioners v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007); CAISO, 160 FERC ¶ 61,035 at P 19 (2017); SPP, 119 FERC ¶ 61,199 at P 28 (2007), *order on reh'g*, 121 FERC ¶ 61,196 (2007); *see also* 178 FERC ¶ 61,088, at PP 29–31 (2022); 179 FERC ¶ 61,103, at PP 20-21 (2022).

158 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.2 Reactive Supply and Voltage Control Credits, Rev. 96 (Dec. 21, 2022).

159 OATT Schedule 2.

160 See OA Schedule 1 § 3.2.3B.

161 OATT Schedule 2.

162 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.3 Reactive Supply and Voltage Control Charges, Rev. 97 (Dec. 21, 2022).

163 See *Reactive Supply Compensation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD16-17-000 (March 17, 2016) (Notice of Workshop).

164 *Reactive Power Capability Compensation*, 177 FERC ¶ 61,118 (2021).

165 See Comments of the Independent Market Monitor for PJM, Docket No. RM22-2-000 (February 22, 2022); Reply Comments of the Independent Market Monitor for PJM, Docket No. RM22-2-000 (March 23, 2022); see also Comments of the Independent Market Monitor for PJM, Docket No. AD16-17-000 (July 29, 2016).

166 *See MISO*, 182 FERC ¶ 61,033 at P 52 (January 27, 2023) (*MISO*); *see also Standardization of Generator Interconnection Agreements & Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at P 546 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 at P 28, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. National Association of Regulatory Utility Commissioners v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007); CAISO, 160 FERC ¶ 61,035 at P 19 (2017); SPP, 119 FERC ¶ 61,199 at P 28 (2007), *order on reh'g*, 121 FERC ¶ 61,196 (2007); *see also* 178 FERC ¶ 61,088, at PP 29–31 (2022); 179 FERC ¶ 61,103, at PP 20-21 (2022).

167 See *Standardization of Generator Interconnection Agreements & Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at P 546 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 at P 28, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. National Association of Regulatory Utility Commissioners v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007); CAISO, 160 FERC ¶ 61,035 at P 19 (2017); CAISO, 119 FERC ¶ 61,199 at P 28 (2007), *order on reh'g*, 121 FERC ¶ 61,196 (2007); *see also SPP*, 178 FERC ¶ 61,088, at PP 29–31 (2022); 179 FERC ¶ 61,103, at PP 20-21 (2022)

168 Attachment O.

AEP Method was created, before the creation of the PJM markets, by a regulated utility that had regulatory and financial reasons to want to define some generation costs as transmission costs. At the time, AEP collected both generation and transmission costs under the same cost of service approach. The *AEP* method was based on three sentences in testimony filed in 1993 that provide no logical, engineering or economic support for allocating a part of generator capital investment to reactive. That testimony was about a subjective decision to reassign costs that were already fully accounted for and not about any asserted costs to provide reactive power that were not recovered elsewhere and not for any asserted additional costs of providing reactive power.[169]

In PJM and its competitive market design, there is no reason to include complex rules that arbitrarily segregate a portion of a resource's capital costs as related to reactive power and that require recovery of that arbitrary portion through guaranteed revenue requirement payments based on burdensome cost of service rate proceedings. The practice persists in PJM only because it provides a significant, guaranteed stream of riskless revenue.

Applying cost of service rules is costly and burdensome and unnecessary. Most reactive proceedings for generators in PJM are resolved in black box settlements that fail to address the merits of the cost support provided, result from an unsupported split the difference approach, and that, not surprisingly, produce a wide, unreasonable and discriminatory disparity among the rates per paid per MW-year for the same service.

Payments based on cost of service approaches result in distortionary impacts on PJM markets. Elimination of the reactive revenue requirement and recognition that capital costs are not distinguishable by function would increase prices in the capacity market. The VRR curve would shift to the right, the maximum VRR price would increase and offer caps in the capacity market would increase. The simplest way to address this distortion would be to recognize that all capacity costs are recoverable in the PJM markets.

The NOI presents an opportunity to address the reactive issue using a market based approach. The best approach would be to issue a rule eliminating cost of service rates for reactive capability and allowing for recovery of capacity costs through existing markets, including a removal of any offset for reactive revenue in offers and in the capacity market demand (VRR) curve. A second best approach would be to limit the revenue requirement that could be filed for under the OATT Schedule 2 to a level less than or equal to the reactive revenue credit included in the capacity market design, in the VRR curve Net CONE value, currently $2,199 per MW-year.

As with all things in PJM markets, it is easy to focus on extreme complexity and lose sight of the big picture. The complexity includes power factors and power factor testing and convoluted and arbitrary allocation factors. The big picture here is that in PJM, the interrelated and self sustaining markets provide the opportunity for all power plants to recover all their costs, including a return on and of capital, including any identifiable reactive costs. There is no reason that part of those capacity costs should be paid directly in a non market, guaranteed, riskless revenue stream rather than in the market. The existence of the current option creates strong incentives for generators to attempt to maximize the allocation of capital costs to reactive in order to maximize guaranteed, nonmarket revenues.

The current process does not actually compensate resources based on their costs of investment in reactive power capability. The *AEP* Method assigns costs between real and reactive power based on a unit's power factor. This is effectively an allocation based on a subjective judgment rather than actual investment. There are few if any identifiable costs incurred by generators in order to provide reactive power. Separately compensating resources based on a judgment based allocation of total capital costs was never and is not now appropriate in the PJM markets. Generating units are fully integrated power plants that produce both the real and reactive power required for grid operation.

There is no logical reason to have a separate fixed payment for any part of the capacity costs of generating units in PJM. If separate cost of service rates for reactive continue, they need to be correctly integrated in the PJM market design.

The best and straightforward solution is to remove revenue requirements for reactive supply capability and to remove the offset. Investment in generation can and should be compensated entirely through markets. Removing rules for revenue requirements would avoid

169 See *Fern Solar LLC*, Initial Brief of the Independent Market for PJM, FERC Docket No. ER20-2186, et al. (February 15, 2023) at 24–31.

the significant waste of resources incurred to develop unneeded cost of service rates.

The result would be to pay generators market based rates for both real and reactive capacity.

The PJM market design allows for the competitive investment in generation resources. The addition of separate rules allowing for the recovery of an arbitrarily defined portion of the same investment on a cost of service basis introduces a flaw into the competitive market design. The flaw is exacerbated when separate cost of service proceedings define the revenue requirement cost to supply reactive at values ranging from $13,044 to $964 per MW-year. (See Table 10-78)

The real issue is that the revenue requirement approach is inconsistent with both the theory and mechanics of PJM markets. The impact is to distort market outcomes.

The rules that account for recovery of reactive revenues are built into the auction parameters, specifically, the VRR curve. The PJM market rules explicitly account for recovery of reactive revenues of $2,199 per MW-Year through inclusion in the Net CONE parameter of the capacity market demand (VRR) curve.[170] The Net CONE parameter directly affects clearing prices by affecting both the maximum capacity price and the location of the downward sloping part of the VRR curve. In addition, market sellers, when submitting offers based on net avoidable costs must account for revenues received through cost of service reactive capability rates in the calculation.[171] Unit specific reactive capability rates up to that $2,199 per MW-Year level are at least consistent with that parameter. Reactive capability rates either above or below that level distort capacity market outcomes. For example, a marginal resource with reactive revenue of $5,000 per MW-Year reflected in their net ACR offer would suppress the capacity market clearing price. Conversely, a marginal resource with a reactive revenue of $1,000 per MW-Year reflected in their net ACR offer would inflate the capacity market clearing price.

Interconnection Requirements

A generating facility is not eligible for reactive payments when it is not connected directly to the PJM system and therefore does not provide reactive capability to PJM under Schedule 2, and should not receive payments for a service that it does not and cannot provide. In a number of cases now pending, the Market Monitor has challenged the eligibility of resources filing under OATT Schedule 2 because they are interconnected to facilities that PJM does not monitor and does not rely on to provide reactive capability.[172]

Schedule 2 provides, “Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided *directly* by the Transmission Provider” [emphasis added]. PJM cannot rely on resources on an adjacent unmonitored system to directly provide reactive capability because the adjacent unmonitored system is under the control of another entity. PJM cannot attempt to directly dispatch a resource on an adjacent system without knowing the voltage conditions on that system. PJM would have to request assistance and cooperation of the entity responsible for the adjacent unmonitored system. Including a third party in the dispatch decision means PJM is not relying on the resources to directly provide Reactive Supply and Voltage Control Service.

The best place to understand PJM’s role regarding the Lines is in the Designated Facilities List contained in the PJM manual on Transmission Operations referenced in the definition of Transmission Provider. PJM Manual 3 (Transmission Operations) sets forth the criteria for determining Monitored Transmission Facilities and the criteria for determining Reportable Transmission Facilities. PJM explains that “Monitored Transmission Facilities are monitored and controlled for limit violations using PJM’s Security Analysis programs.”[173] PJM explains that transmission facilities are ”reportable if a change of its status can affect, or has the potential to affect, a transmission constraint on any Monitored Transmission Facility,” or “if it impedes the free-flowing ties within the PJM RTO and/or adjacent areas.”[174] The Monitored and Reportable Transmission Facilities are included in the Transmission Facilities List. The Transmission Facilities List is located on the PJM website.

PJM’s criteria for defining Monitored Transmission Facilities and the criteria for defining Reportable Transmission Facilities determine which power lines

170 *See* OATT Attachment DD § 5.10(a)(v)(A).
171 OATT Attachment DD § 6.8(d).

172 See, e.g., FERC Docket Nos. ER21-2091, ER21-936, ER21-737, ER20-1863 & ER20-1851.
173 See PJM Manual 03: Transmission Operations, Rev. 63 (Nov. 16, 2022).
174 See PJM, PJM Transmission Providers Facilities List On-Line Help (Last Updated: May 4, 2017), which can be accessed at: <trans-fac-help.ashx (pjm.com)>.

constitute the PJM transmission system and which do not.

A resource interconnected on power lines that fail to meet the criteria defining Monitored Transmission Facilities *and* the criteria for defining Reportable Transmission Facilities are not interconnected to PJM's transmission facilities. PJM is not the Transmission Provider for such power lines. PJM does not directly rely on resources to provide Reactive Supply and Voltage Control Service, and they are therefore ineligible for compensation under Schedule 2.[175]

In an initial decision issued July 15, 2022, the first decision addressing the issue, the Presiding Judge found: "Schedule 2 contains two eligibility criteria for generation facilities: (1) that the facility must be under the control of PJM, and (2) that the facility must be operationally capable of providing voltage support to PJM's transmission facilities such that PJM can rely on that generation facility to maintain transmission voltages."[176] The Judge determined that none of the facilities in the four cases at hearing "satisfy the second criterion."[177] In the initial decision, the Presiding Judge did not accept the MMU's theory of the case on eligibility, but the initial decision found that power flow evidence could not use off system reactive capability to support voltage levels on the transmission system.[178] The initial decision provides a reasonable resolution to the eligibility issue. The principal advantage of the MMU's approach is that it provides for a general finding that PJM lacks capability to rely on off system resources for reactive capability based on the information available to PJM dispatchers regardless of what power flow analyses show. The issue will be decided by the Commission.

The issue of eligibility is significant because the number of facilities interconnecting at points that are not on the PJM system is expected to increase. Such facilities do not contribute reactive capability to PJM, and based on anticipated power factor levels and the way the *AEP* Method has been applied for calculating reactive rates under Schedule 2, such facilities would receive significantly larger payments per MW than the facilities that do provide reactive power capability useful to PJM.[179] These payments are for services not provided, but also would distort the PJM Capacity Market by paying a large share of the fixed costs of such facilities as reactive. This approach is a faulty and inefficient and noncompetitive market design.

Fleet Reactive Rates

Cost of service rates are established under Schedule 2 of the OATT and may cover rates for single units or a fleet of units.[180] Until the Commission took corrective action, fleet rates remained in place in PJM even when the actual units in the fleet changed as a result of unit retirements or sales of units.[181] New rules require unit owners to give notice of fleet changes in an informational filing or to file a new rate based on the remaining units, but do not yet require unit specific reactive rates.[182]

Table 10-74 identifies fleet rates currently effective in PJM.

Table 10-74 Fleet rates currently effective in PJM

Company	Fleet Rates	Number of Resources	FERC Dockets
Indiana Municipal Power Agency	$489,001.00	5	ER05-971-000
PBF Power Marketing (DCRC)	$588,597.00	3	ER14-357
Dominion Virginia Power	$27,500,000.00	66	ER06-554, ER17-512
Ingenco Wholesale Power, LLC	$888,913.24	11	ER20-1863

Fleet rates create confusion about what revenue is properly attributable to each unit in the fleet. Reactive rates should be stated separately for each unit, even if multiple plants or units are considered in a single proceeding. The MMU filed with the Commission to require unit specific rates when PJM proposed limited reforms that could have corrected the oversight and compliance problems posed by fleet rates.[183] But PJM rules require fleet owners only to submit informational filings when a reactive unit is transferred or deactivated.[184] The current rules do not require a rate filing, which would place the burden of proof on the company and allow for cost review.[185]

The MMU also raised issues related to fleet rates in a settlement establishing a fleet rate without specifying the actual portion of the fleet rate attributable to each

175 A facility that does not meet the criteria defining Reportable Transmission Facilities but does meet the criteria for defining Monitored Transmission Facilities is also not eligible under Schedule 2. If PJM does not operate the Lines, they are not PJM's transmission facilities. There is no evidence that PJM would rely on a resource to provide Reactive Supply and Voltage Control Service if the resource was located on a portion of the grid that PJM was monitoring but not operating. Coordination with the responsible operator would still be needed.
176 See 180 FERC ¶ 63,009 at P 5 (2022).
177 *Id.*
178 *Id.*
179 See 80 FERC ¶ 63,006 (1997), *aff'd*, 88 FERC ¶ 61,141 (1999).
180 See, e.g., OATT Schedule 2; 114 FERC ¶ 61,318 (2006).
181 See 149 FERC ¶ 61,132 (2014); 151 FERC ¶ 61,224 (2015); OATT Schedule 2.
182 *Id.*
183 151 FERC ¶ 61,224 at P 29 (2015).
184 OATT Schedule 2.
185 *Id.*

unit in the fleet.[186] The approach could prevent or inhibit an appropriate adjustment of the fleet requirement if a unit receiving an unspecified portion of such requirement is deactivated or transferred because third parties without access to cost information would bear the burden of proof in a complaint proceeding.[187] The MMU also explained that the approach makes it impossible to calculate cost-based offers from such units in the PJM Capacity Market. The settlement was approved over the MMU's objection on the grounds that the tariff does not prohibit fleet rates.[188]

The MMU recommends that fleet rates be eliminated and that compensation be based on unit specific costs and rates and that rates be appropriately reduced when units with reactive payments retire.

Reactive Costs

In 2022, total reactive charges were $385.5 million, an increase of $19.9 million (5.4 percent) from 2021. In 2022, total reactive capability charges were $384.0 million, an increase of $19.3 million (5.3 percent) from 2021. In 2022, total reactive service charges were $1.5 million, an increase of $0.6 million (66.2 percent) from 2021. In 2022, $1.5 million for reactive service charges were paid to 18 units for operation in 89 unit hours.

Table 10-75 shows reactive service charges for the first nine months of each year from 2010 through 2022.

Table 10-75 Reactive service charges and reactive capability charges: 2010 through 2022

Year	Reactive Service Charges	Reactive Capability Charges	Total
2010	$69,314,376	$241,994,431	$311,308,807
2011	$44,568,672	$255,910,059	$300,478,731
2012	$76,100,839	$272,864,535	$348,965,374
2013	$312,640,950	$276,918,698	$589,559,649
2014	$29,560,453	$280,840,576	$310,401,029
2015	$10,543,187	$276,567,702	$287,110,889
2016	$2,498,279	$294,389,603	$296,887,882
2017	$20,379,379	$302,704,116	$323,083,495
2018	$13,183,120	$303,465,206	$316,648,326
2019	$570,589	$329,215,657	$329,786,246
2020	$428,629	$369,345,209	$369,773,838
2021	$909,343	$364,698,096	$365,607,440
2022	$1,511,630	$383,974,727	$385,486,357

Table 10-76 shows zonal reactive service charges for 2021 and 2022, reactive capability charges and total charges. Reactive service charges show charges to each zone for reactive service. Reactive capability charges show charges to each zone for reactive capability.

186 *See* Letter Opposing Settlement, Docket No ER06-554 et al. (June 14, 2017).
187 *Id.*
188 162 FERC ¶ 61,029 (2018).

Table 10-76 Reactive service charges and reactive capability charges by zone: 2021 and 2022

	2021			2022		
Zone	Reactive Service Charges	Reactive Capability Charges	Total Charges	Reactive Service Charges	Reactive Capability Charges	Total Charges
ACEC	$0	$4,289,651	$4,289,651	$0	$3,491,805	$3,491,805
AEP	$42,352	$48,754,623	$48,796,975	$0	$52,783,749	$52,783,749
APS	$0	$20,195,511	$20,195,511	$0	$22,388,540	$22,388,540
ATSI	$0	$26,718,720	$26,718,720	$0	$29,653,416	$29,653,416
BGE	$0	$6,635,411	$6,635,411	$267,035	$6,567,885	$6,834,920
COMED	$149,929	$40,934,537	$41,084,466	$0	$44,574,560	$44,574,560
DAY	$0	$2,814,025	$2,814,025	$0	$2,785,388	$2,785,388
DUKE	$0	$10,014,923	$10,014,923	$0	$9,013,598	$9,013,598
DOM	$0	$46,033,237	$46,033,237	$225,700	$50,008,103	$50,233,803
DPL	$1,517	$10,398,016	$10,399,534	$260,580	$9,843,517	$10,104,097
DUQ	$0	$570,288	$570,288	$0	$202,150	$202,150
EKPC	$1,231	$2,178,720	$2,179,951	$0	$2,156,548	$2,156,548
JCPLC	$0	$7,532,142	$7,532,142	$0	$7,648,680	$7,648,680
MEC	$8,696	$6,108,938	$6,117,634	$65,587	$5,983,685	$6,049,272
OVEC	$0	$0	$0	$0	$0	$0
PECO	$0	$20,916,523	$20,916,523	$0	$20,407,181	$20,407,181
PE	$0	$17,304,838	$17,304,838	$0	$17,296,482	$17,296,482
PEPCO	$0	$9,882,533	$9,882,533	$483,396	$9,633,086	$10,116,482
PPL	$705,618	$36,631,317	$37,336,935	$209,332	$36,302,290	$36,511,621
PSEG	$0	$27,821,693	$27,821,693	$0	$29,596,003	$29,596,003
REC	$0	$0	$0	$0	$0	$0
(Imp/Exp/Wheels)	$0	$18,962,450	$18,962,450	$0	$23,638,061	$23,638,061
Total	$909,343	$364,698,096	$365,607,440	$1,511,630	$383,974,727	$385,486,357

Table 10-77 shows the units which received reactive service credits in 2022.

Table 10-77 Reactive service credits by plant (Total dollars): 2022

		2022
Zone	Plant	Reactive Service Credits
BGE	BC BRANDON SHORES 1 F	$264,582
BGE	BC PERRYMAN 51 F	$2,453
DPL	DPL BAYVIEW 1 D	$2,668
DPL	DPL BAYVIEW 2 D	$2,927
DPL	DPL BAYVIEW 3 D	$1,920
DPL	DPL BAYVIEW 4 D	$962
DPL	DPL DEMEC - CLAYTON 1 CT	$6,048
DPL	DPL EASTON DIESEL	$24,883
DPL	DPL INDIAN RIVER 4 F	$221,172
MEC	ME MOUNTAIN 2 CT	$55,027
MEC	ME TOLNA 2 CT	$10,560
PEPCO	PEP CHALKPOINT 4 F	$483,396
PPL	PL HAZELTON 1 CT	$62,967
PPL	PL HAZELTON 2 CT	$88,621
PPL	PL HAZELTON 3 CT	$39,911
PPL	PL HAZELTON 4 CT	$17,834
DOM	VP ELIZABETH RIVER 1 CT	$206,962
DOM	VP ELIZABETH RIVER 3 CT	$18,738
Total		$1,511,630

Table 10-78 shows the settled reactive capability revenue requirements by technology effective on December 1, 2022.[189] These revenue requirements do not include revenue requirements that were filed but not yet final. The table demonstrates the wide disparity in payments for reactive capability that result from the current cost of service rate case model settlement process.

189 The total amount in the final row of Table 10-32 is the amount that would be paid if the total rate effective on December 1, 2022 were effective for an entire year. The total rates effective on any given day depend on requests made by resource owners in filings to FERC and FERC approval of those rates.

Table 10-78 Total settled reactive revenue requirements by unit type and fuel type: December 1, 2022

Unit Type	Fuel Type	Total Revenue Requirement per Year	MW	Number of Resources	Requirement per MW-year
CC	Gas	$123,826,766.19	49,444.2	155	$2,504.37
CT	Gas	$45,497,906.52	28,281.7	247	$1,608.74
CT	Oil	$4,618,677.69	3,241.2	111	$1,424.99
Diesel	Gas	$1,380,092.00	105.8	5	$13,044.35
Diesel	Oil	$1,028,787.05	168.2	36	$6,116.45
Diesel	Other - Gas	$915,140.45	115.4	11	$7,930.16
FC	Gas	$45,000.00	2.6	1	$17,307.69
Hydro	Water	$17,811,640.52	6,891.4	52	$2,584.62
Nuclear	Nuclear	$57,520,512.74	32,648.6	31	$1,761.81
Solar	Solar	$3,409,893.89	424.1	15	$8,040.31
Steam	Coal	$53,326,350.50	41,241.3	67	$1,293.03
Steam	Gas	$5,202,743.36	5,603.6	18	$928.46
Steam	Oil	$3,515,166.43	2,872.3	9	$1,223.82
Steam	Other - Solid	$340,000.00	34.0	2	$10,000.00
Steam	Wood	$207,588.13	153.0	3	$1,356.79
Wind	Wind	$18,664,267.97	5,028.5	37	$3,711.70
Total		$337,310,533.44	176,255.9	800	$1,913.75

Frequency Response

On February 15, 2018, the Commission issued Order No. 842, which modified the pro forma large and small generator interconnection agreements and procedures to require newly interconnecting generating facilities, both synchronous and nonsynchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.[190] Such equipment must include a governor or equivalent controls with the capability of operating at a maximum 5 percent droop and ±0.036 Hz deadband (or the equivalent or better).

PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[191]

The MMU recommends that the same capability be required of both new and existing resources. The MMU agrees with Order No. 842 that RTOs not be required to provide additional compensation specifically for frequency response. The current PJM market design provides compensation for all capacity costs, including these, in the capacity market. The current market design provides compensation, through heat rate adjusted energy offers, for any costs associated with providing frequency response. Because the PJM market design already compensates resources for frequency response capability and any costs associated with providing frequency response, any separate filings submitted on behalf of resources for compensation under section 205 of the Federal Power Act should be rejected as double recovery.

Frequency Control Definition

There are four distinct types of frequency control, distinguished by response timeframe and operational nature: Inertial Response, Primary Frequency Response, Secondary Frequency Control (Regulation), and Tertiary Frequency Control (Primary Reserve).

- **Inertial Response.** Inertial response to frequency excursion is the natural resistance of rotating mass turbine generators to changes in their stored kinetic energy. This response is immediate and resists short term changes to ACE from the instant of the disturbance up to twenty seconds after the disturbance.
- **Primary Frequency Response.** Primary frequency response is a response to a disturbance based on a local detection of frequency and local operational control settings. Primary frequency response begins within a few seconds and extends up to a minute. The purpose of primary frequency response is to arrest and stabilize the system until other measures (secondary and tertiary frequency response) become active.

190 157 FERC ¶ 61,122 (2016).
191 See 164 FERC ¶ 61,224 (2018).

- **Secondary Frequency Control.** Secondary frequency control is called regulation. In PJM it begins to respond within 10 to 15 seconds and can continue up to an hour. Regulation is controlled by PJM which detects the grid frequency, calculates a counterbalancing signal, and transmits that signal to all regulating resources.
- **Tertiary Frequency Control.** Tertiary frequency control and imbalance control lasting 10 minutes to an hour is called primary reserve.

VACAR Reserve Sharing Agreement

The VACAR Reserve Sharing Agreement (VRSA) was a combination of agreements among the entities in the VACAR subregion including Dominion.[192] VACAR is a subregion of the SERC Reliability Corporation (SERC) region. The agreement was terminated on October 1, 2022. The agreement required that each entity maintain primary reserves to meet the VACAR contingency reserve commitment (VACAR reserves) and deploy such reserves in the case of an emergency (e.g. loss of a unit in VACAR).[193] Dominion was the only party to the VRSA that is also a transmission owner and a generation owner in PJM. The VRSA was not a public agreement. PJM was not a party to the VRSA. However, as the reliability coordinator for Dominion Virginia Power, PJM was responsible for scheduling Dominion's required reserves in the SERC region as described in the PJM manuals.[194]

PJM procures synchronized reserves and primary reserves for the PJM region, including Dominion. The synchronized reserve and primary reserve requirements are equal to the largest single contingency and 150 percent of the largest contingency. The requirement is procured separately for the RTO and the MidAtlantic Dominion area (MAD) when the largest contingency is located outside of MAD. All units in PJM that meet the synchronized or primary reserve operating parameter requirements are eligible to meet the synchronized and primary requirements as long as PJM does not deselect them. Starting October 1, 2022, PJM also procures 30 minute reserves. The 30 minute reserve requirement is equal to the greatest of 3,000 MW, the primary reserve requirement, and the largest active gas contingency, plus 190 MW.[195]

Prior to October 1, 2022, PJM procured Day-Ahead Scheduling Reserves (DASR) for the PJM region, including Dominion, as Secondary Reserves. The DASR requirement was calculated daily and was equal to the peak load forecast for the ReliabilityFirst region (RFC) and EKPC times the sum of the forced outage rate and the load forecast error, plus Dominion's share of the VACAR contingency reserve commitment. All units in PJM that met the DASR operating parameter requirements were eligible to meet the DASR requirement.[196] There was no requirement that a specific amount of DASR be located in Dominion. Equation 1 shows the DASR requirement calculation.[197]

Equation 1: DASR Requirement Formula

$$\text{DASR Requirement} = (\text{RFC and EKPC Peak}) \times (\text{FOR} + \text{LFE}) + \text{DOM VACAR}$$

Beginning October 1, 2022, reserve requirements in PJM are no longer tied to reserve requirements in VACAR.

PJM implemented the reserve market changes effective October 1, 2022. These changes include the consolidation of synchronized reserves tier 1 and tier 2 and the reserve must offer requirement. With these changes, it would not have been possible for Dominion to hold reserves to meet its obligations under the VRSA without failing the must offer requirement in PJM. Under the reserve market changes, it would not have been possible for Dominion to meet both the VRSA and the PJM reserve rules.

Recommendations

The Market Monitor recommends that the VRSA be terminated and, if necessary, replaced by a reserve sharing agreement between PJM and VACAR South, similar to agreements between PJM and other bordering areas. Effective October 1, 2022, Dominion exited the VACAR Reserve Sharing group which effectively terminated the VRSA.[198]

192 VRSA entities: Dominion, Duke Energy Progress, Duke Energy Carolinas, South Carolina Electric & Gas Company, South Carolina Public Service Authority and Cube Hydro Carolinas.
193 *See* SERC Regional Criteria, Contingency Reserve Policy, NERC Reliability Standard BAL-002 at 10-11.
194 See PJM. "Manual 13: Emergency Operations," Rev. 86 (Nov. 3, 2022).
195 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3 Reserve Requirement Determination, Rev. 122 (Oct. 1, 2022).
196 DASR can be provided by units that do not clear the day-ahead energy market and can start within 30 minutes or by units that clear the day-ahead energy market and can ramp up within 30 minutes.
197 During cold weather alerts and hot weather alerts, the DASR requirement is increased to procure additional reserves.
198 *See* "Reserve Price Formation – Manual Revisions – M10, M12, M13," PJM presentation to the Markets and Reliability Committee. (September 21, 2022) <https://pjm.com/-/media/committees-groups/committees/mrc/2022/20220921/consent-agenda-b---1-manuals-10-12-13-reserve-price-formation-revision---presentation.ashx>.